EB-2015-0240

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act*, *1998*, S.O. 1998, c.15, Schedule B;

AND IN THE MATTER OF an application by Essex Powerlines Corporation for an order approving a Smart Meter Disposition Rate Rider ("SMDR") and a Smart Meter Incremental Rate Rider ("SMIRR"), each to be effective January 1, 2015;

AND IN THE MATTER OF an application by Essex Powerlines Corporation for an order approving just and reasonable rates and other charges for electricity distribution to be effective May 1, 2015;

AND IN THE MATTER OF a motion to review under Rule 41.01 of the *Rules of Practice and Procedure*.

BOOK OF AUTHORITIES OF THE SCHOOL ENERGY COALITION

September 8, 2015

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** Preliminary Version **

Case Name:

Bell Canada v. Bell Aliant Regional Communications

Bell Canada, Appellant;
v.
Bell Aliant Regional Communications, Limited Partnership, Consumers' Association of Canada, National Anti-Poverty Organization, Public Interest Advocacy Centre, MTS Allstream Inc., Société en commandite Télébec and TELUS Communications Inc., Respondents, and Canadian Radio-television and Telecommunications Commission, Intervener.
And between
TELUS Communications Inc., Appellant;
v.
Bell Canada, Arch Disability Law Centre, Bell Aliant Regional Communications, Limited Partnership, Canadian Radio-television and Telecommunications Commission, Consumers' Association of Canada, National Anti-Poverty Organization, Public Interest Advocacy Centre, MTS Allstream Inc., Saskatchewan Telecommunications and Société en commandite Télébec, Respondents.
And between
Consumers' Association of Canada and National Anti-Poverty Organization, Appellants;
v.
Canadian Radio-television and Telecommunications Commission, Bell Aliant Regional Communications, Limited Partnership, Bell Canada, Arch Disability Law Centre, MTS Allstream Inc., TELUS Communications Inc. and TELUS Communications (Québec) Inc., Respondents.

[2009] S.C.J. No. 40

[2009] A.C.S. no 40

2009 SCC 40

[2009] 2 S.C.R. 764

[2009] 2 R.C.S. 764

310 D.L.R. (4th) 608

392 N.R. 323

J.E. 2009-1708

EYB 2009-163783

92 Admin. L.R. (4th) 157

2009 CarswellNat 2717

File Nos.: 32607, 32611.

Supreme Court of Canada

Heard: March 26, 2009;
Judgment: September 18, 2009.

Present: McLachlin C.J. and Binnie, LeBel, Deschamps, Fish, Abella, Charron, Rothstein and Cromwell JJ.

(78 paras.)

Appeal From:

ON APPEAL FROM THE FEDERAL COURT OF APPEAL

Administrative law -- Judicial review and statutory appeal -- Standard of review -- Reasonableness -- Deference to expertise of decision maker -- Appeals from Federal Court of Appeal judgment concerning the authority of the Canadian Radio-television and Telecommunications Commission dismissed -- CRTC directed that deferral accounts be used to improve accessibility and for broadband expansion, with any remaining funds to be distributed to certain customers -- Issues raised went to the very heart of CRTC's specialized expertise -- Core of the issue was methodology for setting rates and allocation of certain proceeds derived from rates, an exercise with which CRTC was statutorily charged and which it was uniquely qualified to undertake -- This suggested a more deferential standard of review, the standard of reasonableness -- CRTC properly exercised its authority.

Media and communications law -- Telecommunications -- Telecommunications policy -- Rate regulation -- Rates for telecommunication services -- Methodology -- Appeals from a judgment of the Federal Court of Appeal concerning the authority of the Canadian Radio-television and Telecommunications Commission dismissed -- CRTC directed that deferral accounts be used to improve accessibility for individuals with disabilities and for broadband expansion, with any remaining funds to be distributed to certain customers -- The CRTC properly exercised its authority -- The CRTC *acted reasonably and in accordance with the policy objectives of the Telecommunications Act -- The CRTC properly treated the statutory objectives as guiding principles in the exercise of its rate-setting authority, and came to a reasonable conclusion.*

Media and communications law -- Canadian Radio-television and Telecommunications Commission reviews and appeals -- Judicial review -- Grounds for review -- Jurisdiction -- Appeals from Federal Court of Appeal judgment concerning the authority of the Canadian Radio-television and Telecommunications Commission dismissed -- CRTC directed that deferral accounts be used to improve accessibility and for broadband expansion, with any remaining funds to be distributed to certain customers -- Issues raised went to the very heart of CRTC's specialized expertise -- Core of the issue was methodology for setting rates and allocation of certain proceeds derived from rates, an exercise with which CRTC was statutorily charged and which it was uniquely qualified to undertake -- This suggested a more deferential standard of review, the standard of reasonableness -- CRTC properly exercised its authority.

Appeals by Bell Canada, Telus, and Consumers' Association of Canada and national Anti-Poverty Organization from a judgment of the Federal Court of Appeal concerning the authority of the Canadian Radio-television and Telecommunications Commission (CRTC). Exercising its rate-setting authority, the CRTC had issued a decision establishing a formula to regulate the maximum prices charged for certain services offered by incumbent local exchange carriers. The CRTC ordered telephone carriers to establish deferral accounts to record funds representing the difference between the rates actually charged and those as otherwise determined by the CRTC's formula. The CRTC subsequently decided that each deferral account should be used to improve accessibility to telecommunications services for individuals with disabilities and for broadband expansion in rural and remote communities. Any remaining funds were ordered to be distributed to certain customers. Bell Canada appealed the order directing the distribution of funds to customers. The Consumers' Association of Canada and the National Anti-Poverty Organization appealed the direction that the funds be used for the expansion of broadband infrastructure. The Federal Court of Appeal dismissed the appeals, finding that it was always contemplated the future disposition of the deferral account funds as the CRTC would direct, and that the CRTC acted within its broad mandate to pursue its regulatory objectives. Bell Canada argued that the CRTC had no statutory authority to order what it claimed amounted to retrospective rebates to consumers. In its view, the distributions ordered by the CRTC were in substance a variation of rates that had been declared final. The Consumers' Association of Canada and the National Anti-Poverty Organization argued that the rest of the deferral account balances should be distributed to customers in full, and that the CRTC had no authority to allow the use of the funds for broadband expansion.

HELD: Appeals dismissed. The CRTC properly exercised its authority. The issues raised in the appeals went to the very heart of the CRTC's specialized expertise. The core of the issue was with the methodology for setting rates and the allocation of certain proceeds derived from those rates, a polycentric exercise with which the CRTC was statutorily charged and which it was uniquely qualified to undertake. This suggested a more deferential standard of review, the standard of reasonableness. The CRTC acted reasonably and in accordance with the policy objectives of the Telecommunications Act in allowing the use of funds for broadband expansion and directing that any remaining funds be distributed to customers. The deferral accounts, and the encumbrance to which the funds recorded in them were subject, were an integral part of the rate-setting exercise ensuring that the rates approved were just and reasonable. It followed that the deferral accounts decision did not change any prior CRTC decision. Consequently, the CRTC's later allocation of deferral account balances for various purposes, including customer credits, was not a variation of a final rate order. As for Consumers' appeal, the CRTC properly considered the objectives set out in s. 7 when it ordered expenditures for the expansion of broadband infrastructure and consumer credits. It had the statutory authority to set just and reasonable rates, to establish the deferral accounts, and to direct the disposition of the funds in those accounts. It was obliged to balance and consider a wide variety of objectives and interests and did so in a reasonable way.

Statutes, Regulations and Rules Cited:

Railway Act, R.S.C. 1985, c. R-3, s. 340(1)

Telecommunications Act, S.C. 1993, c. 38, s. 7, s. 24, s. 25(1), s. 27, s. 32(g), s. 35(1), s. 37(1), s. 42(1), s. 46.5(1), s. 47, s. 47(a), s. 52(1)

Subsequent History:

NOTE: This document is subject to editorial revision before its reproduction in final form in the Canada Supreme Court Reports.

Court Catchwords:

Communications law -- Telephone -- Regulation of rates charged by telecommunications carriers -- Canadian Radio-television and Telecommunications Commission ordering carriers to create deferral accounts -- Accounts being collected from urban residential telephone service revenues to enhance competition -- CRTC directing that accounts be disposed of to increase accessibility of telecommunications services for persons with disabilities and to expand broadband coverage -- Remaining amounts, if any, being distributed to subscribers -- Whether Telecommunications Act authorizes CRTC to direct disposition of deferral account funds as it did -- Telecommunications Act, S.C. 1993, c. 38, ss. 7, 47.

Administrative law -- Appeals -- Standard of review -- Canadian Radio-television and Telecommunications Commission -- Standard of review applicable to CRTC's decision to direct disposition of deferral accounts -- Telecommunications Act, S.C. 1993, c. 38, ss. 7, 47, 52(1).

Court Summary:

In May 2002, the Canadian Radio-television and Telecommunications Commission ("CRTC"), in the exercise of its rate-setting authority, established a formula to regulate the maximum prices to be charged for certain services offered by incumbent local exchange carriers, including for residential telephone services in mainly urban non-high cost serving areas (the "Price Caps Decision"). Under the formula established by the Price Caps Decision, any increase in the price charged for these services in a given year was limited to an inflationary cap, less a productivity offset to reflect the low degree of competition in that particular market. The CRTC ordered the carriers to establish deferral accounts as separate accounting entries in their ledgers to record funds representing the difference between the rates actually charged and those as otherwise determined by the formula. At the time, the CRTC did not direct how the deferral account funds were to be used.

In December 2003, Bell Canada sought approval from the CRTC to use the balance in its deferral account to expand high-speed broadband internet services in remote and rural communities. The CRTC invited submissions and conducted a public process to determine the appropriate disposition of the deferral accounts. In February 2006, it decided that each deferral account should be used to improve accessibility for individuals with disabilities and for broadband expansion. Any unexpended funds were to be distributed to certain current residential subscribers through a one-time credit or via prospective rate reductions. This was known as the "Deferral Accounts Decision".

Bell Canada appealed the order of one-time credits, while the Consumers' Association of Canada and the National Anti-Poverty Organization appealed the direction that the funds be used for broadband expansion. The Federal Court of Appeal dismissed the appeals, finding that the Price Caps Decision regime always contemplated that the disposition of the deferral accounts would be subject to the CRTC's directions and that the CRTC was at all times acting within its mandate. TELUS Communications Inc. joined Bell Canada as an appellant in this Court.

Held: The appeals should be dismissed.

The CRTC's creation and use of the deferral accounts for broadband expansion and consumer credits was authorized by the provisions of the *Telecommunications Act* which lays out the basic legislative framework of the Canadian telecommunications industry. In particular, s. 7 of the Act sets out certain broad telecommunications policy objectives and s. 47(*a*) directs the CRTC to implement them when exercising its statutory authority, balancing the interests of consumers, carriers and competitors. A central responsibility of the CRTC is to determine and approve just and reasonable rates to be charged for telecommunications services. Pursuing policy objectives through the exercise of its rate-setting power is precisely what s. 47 requires the CRTC to do in setting just and reasonable rates. [para. 1] [para. 28] [para. 36]

The issues raised in these appeals go to the very heart of the CRTC's specialized expertise. The core of the quarrel in effect is with the methodology for setting rates and the allocation of certain proceeds derived from those rates, a polycentric exercise with which the CRTC is statutorily charged and which it is uniquely qualified to undertake. The standard of review is therefore reasonableness. [para. 38]

In ordering subscriber credits and approving the use of funds for broadband expansion, the CRTC acted reasonably and in accordance with the policy objectives of the *Telecommunications Act*. In the Price Caps Decision, the CRTC indicated that the amounts in the deferral accounts would help achieve the CRTC's objectives. When the CRTC approved the rates derived from the Price Caps Decision, the portion of the revenues that went into the deferral accounts remained subject to the CRTC's further directions. The deferral accounts, and the fact that they were encumbered by the possibility of the CRTC's future directions, were therefore an integral part of the rate-setting exercise. The allocation of deferral account funds to consumers was neither a variation of a final rate nor, strictly speaking, a rebate. From the Price Caps Decision onwards, it was understood that the disposition of the deferral account funds might include an eventual credit to subscribers once the CRTC determined the appropriate allocation. [paras. 64-65] [para. 77]

There was no inappropriate cross-subsidization between residential telephone services and broadband expansion. The *Telecommunications Act* contemplates a comprehensive national telecommunications framework. The policy objectives that the CRTC is always obliged to consider demonstrate that it need not limit itself to considering solely the service at issue in determining whether rates are just and reasonable. It properly treated the statutory objectives as guiding principles in the exercise of its rate-setting authority, and came to a reasonable conclusion. [para. 73] [para. 75] [para. 77]

Cases Cited

Referred to: Telecom Decision CRTC 2002-34; Telecom Decision CRTC 2005-69; Telecom Decision CRTC 2003-15; Telecom Decision CRTC 2003-18; Telecom Public Notice CRTC 2004-1; Telecom Decision CRTC 2006-9; Telecom Decision CRTC 2008-1; *Council of Canadians with Disabilities v. VIA Rail Canada Inc.*, 2007 SCC 15, [2007] 1 S.C.R. 650; *Dunsmuir v. New Brunswick*, 2008 SCC 9, [2008] 1 S.C.R. 190; *Canada (Citizenship and Immigration) v. Khosa*, 2009 SCC 12, [2009] 2 S.C.R. 339; *Northwestern Utilities Ltd. v. City of Edmonton*, [1929] S.C.R. 186; *ATCO Gas and Pipelines Ltd. v. Alberta (Energy and Utilities Board)*, 2006 SCC 4, [2006] 1 S.C.R. 140; *Re General Increase in Freight Rates* (1954), 76 C.R.T.C. 12; *Canadian National Railways Co. v. Bell Telephone Co. of Canada*, [1939] 1 S.C.R. 308; Telecom Decision CRTC 97-9; Telecom Decision CRTC 94-19; *Edmonton (City) v. 360Networks Canada Ltd.*, 2007 FCA 106, [2007] 4 F.C.R. 747, leave to appeal refused, [2007] 3 S.C.R. vii; *Barrie Public Utilities v. Canadian Cable Television Assn.*, 2003 SCC 28, [2003] 1 S.C.R. 476; Telecom Decision CRTC 93-9; *Bell Canada v. Canada (Canadian Radio-television and Telecommunications Commission)*, [1989] 1 S.C.R. 1722; *EPCOR Generation Inc. v. Energy and Utilities Board*, 2003 ABCA 374, 346 A.R. 281; *Reference Re Section 101 of the Public Utilities Act* (1998), 164 Nfld. & P.E.I.R. 60.

Statutes and Regulations Cited

Railway Act, R.S.C. 1985, c. R-3, s. 340(1).

Telecommunications Act, S.C. 1993, c. 38, ss. 7, 24, 25(1), 27, 32(*g*), 35(1), 37(1), 42(1), 46.5(1), 47, 52(1).

Authors Cited

Ryan, Michael H. *Canadian Telecommunications Law and Regulation*, loose-leaf ed. Scarborough: Carswell, 1993 (updated 2008).

History and Disposition:

APPEALS from a judgment of the Federal Court of Appeal (Richard C.J. and Noël and Sharlow JJ.A.), 2008 FCA 91, 375 N.R. 124, 80 Admin. L.R. (4th) 159, [2008] F.C.J. No. 397 (QL), 2008 CarswellNat 544, affirming a decision of the Canadian Radio-television and Telecommunications Commission, 2006 LNCRTCE 9 (QL), 2006 CarswellNat 6317. Appeals dismissed.

Counsel:

Neil Finkelstein, Catherine Beagan Flood and *Rahat Godil*, for the appellant/respondent Bell Canada.

Michael H. Ryan, John E. Lowe, Stephen R. Schmidt and *Sonya A. Morgan*, for the appellant/respondent TELUS Communications Inc. and the respondent TELUS Communications (Québec) Inc.

Richard P. Stephenson, Danny Kastner and *Michael Janigan*, for the appellants/respondents the Consumers' Association of Canada and the National Anti-Poverty Organization and the respondent the Public Interest Advocacy Centre.

Michael Koch and *Dina F. Graser*, for the respondent MTS Allstream Inc.

John B. Laskin and *Afshan Ali*, for the respondent/intervener the Canadian Radio-television and Telecommunications Commission.

No one appeared for the respondents Société en commandite Télébec, Arch Disability Law Centre, Bell Aliant Regional Communications, Limited Partnership, and Saskatchewan Telecommunications.

The judgment of the Court was delivered by

1 **ABELLA J.**:-- The *Telecommunications Act*, S.C. 1993, c. 38, sets out certain broad telecommunications policy objectives. It directs the Canadian Radio-television and Telecommunications Commission ("CRTC") to implement them in the exercise of its statutory authority, balancing the interests of consumers, carriers and competitors in the context of the Canadian telecommunications industry. The issue in these appeals is whether this authority was properly exercised.

2 While distinct questions arise in each of the appeals before us, the common problem is whether the CRTC, in the exercise of its rate-setting authority, appropriately directed the allocation of funds to various purposes. In the Bell Canada and TELUS Communications Inc. appeal, the challenged purpose is the distribution of funds to customers, while in the Consumers' Association of Canada and National Anti-Poverty Organization appeal, the impugned allocation was directed at the expansion of broadband infrastructure. For the reasons that follow, in my view the CRTC's allocations were reasonable based on the Canadian telecommunications policy objectives that it is obliged to consider in the exercise of all of its powers, including its authority to approve just and reasonable rates.

<u>Background</u>

3 The CRTC issued its landmark "Price Caps Decision"[1] in May 2002. Exercising its rate-setting authority, the CRTC established a formula to regulate the maximum prices charged for certain services offered by incumbent local exchange carriers ("ILECs"), who are primarily well-established telecommunications carriers.

4 As part of its decision, the CRTC ordered the affected carriers to create separate accounting entries in their ledgers. These were called "deferral accounts". The funds contained in these deferral accounts were derived from residential telephone service revenues in non-high cost serving areas ("non-HCSAs"), which are mainly urban. Under the formula established by the Price Caps Decision, any increase in the price charged for these services in a given year was limited to an inflationary cap, less a productivity offset to reflect the low degree of competition in that particular market.

5 More specifically, the effect of the inflationary cap was to bar carriers from increasing their prices at a rate greater than inflation. The productivity offset, on the other hand, put downward pressure on the rates to be charged. While market forces would normally serve to encourage carriers to reduce both their costs and their prices, the low level of competition in the non-HCSA market led the CRTC to conclude that an offsetting factor was necessary as a proxy for the effect of competition.

6 Given the countervailing factors at work in the Price Caps Decision formula, there was the potential for a decrease in the price of residential services in these areas if inflation fell below a certain level. Rather than mandating such a decrease, however, the CRTC concluded that lower prices, and therefore the prospect of lower revenues, would constitute a barrier to the entry of new carriers into this particular telecommunications market. It therefore ordered that amounts representing the difference between the rates *actually* charged, not including the decrease mandated by the Price Caps Decision formula, and the rates as *otherwise determined* through the formula, were to be collected from subscribers and recorded in deferral accounts held by each carrier. These accounts were to be reviewed annually by the CRTC. The intent of the Price Caps Decision was, therefore, that prices for these services would remain at a level sufficient to encourage market entry, while at the same time maintaining the pressure on the incumbent carriers to reduce their costs.

7 The principal objectives the CRTC intended the Price Caps Decision to achieve were the following:

> a) to render reliable and affordable services of high quality, accessible to both urban and rural area customers;
> b) to balance the interests of the three main stakeholders in telecommunications markets, i.e., customers, competitors and incumbent telephone companies;
> c) to foster facilities-based competition in Canadian telecommunications markets;
> d) to provide incumbents with incentives to increase efficiencies and to be more innovative; and
> e) to adopt regulatory approaches that impose the minimum regulatory burden compatible with the achievement of the previous four objectives. [para. 99]

8 The CRTC discussed the future use of the deferral account funds as follows:

> The Commission anticipates that an adjustment to the deferral account would be made whenever the Commission approves rate reductions for residential local services that are proposed by the ILECs as a result of competitive pressures. The Commission also anticipates that the deferral account would be drawn down to mitigate rate increases for residential service that could result from the approval of exogenous factors or when inflation exceeds productivity. <u>Other draw downs could occur, for example, through subscriber rebates or the funding of initiatives that would benefit residential customers in other ways</u>. [Emphasis added; para. 412.]

At the time, it did not specifically direct how the deferral account funds were to be used, leaving the issue subject to further submissions. While some participants objected to the creation of the deferral accounts, no one appealed the Price Caps Decision (*Bell Canada v. Canadian Radio-television and Telecommunications Commission*, 2008 FCA 91, 375 N.R. 124, at para. 14).

9 The Price Caps Decision was to apply to services offered by Bell Canada, TELUS, and other affected carriers for the four-year period from June 1, 2002 to May 31, 2006. In a decision in 2005, the CRTC extended this price regulation regime for another year to May 31, 2007[2]. The CRTC allowed some draw-downs of the deferral accounts following the Price Caps Decision that are not at issue in these appeals.

10 In March 2003, in two separate decisions, the CRTC approved the rates for Bell Canada and TELUS[3]. In the Bell Canada decision, the CRTC appeared to contemplate the continued operation of the deferral accounts established in the Price Caps Decision. It ordered, for example, that certain tax savings be allocated to the deferral accounts:

> The Commission, in Decision 2002-34, established a deferral account in conjunction with the application of a basket constraint equal to the rate of inflation less a productivity offset to all revenues from residential services in non-HCSAs. The Commission considers that AT&T Canada's proposal to allocate the Ontario GRT and the Quebec TGE tax savings associated with all capped services to the price cap deferral account is inconsistent with that determination. <u>The Commission finds that Bell Canada's proposal to include the Ontario GRT and Quebec TGE tax savings associated with the residential local services in non-HCSAs basket in the price cap deferral account is consistent with that determination.</u> [Emphasis added; para. 32.]

11 On December 2, 2003, Bell Canada sought the approval of the CRTC to use the balance in its deferral account to expand high-speed broadband internet service to remote and rural communities. In response, on March 24, 2004, the CRTC issued a public notice requesting submissions on the appropriate disposition of the deferral accounts[4]. Pursuant to this notice, the CRTC conducted a public process whereby proposals were invited for the disposition of the affected carriers' deferral accounts. The review was extensive and proposals were received from numerous parties.

12 This led to the release of the "Deferral Accounts Decision" on February 16, 2006[5]. In this decision, the CRTC directed how the funds in the deferral accounts were to be used. These directions form the foundation of these appeals.

13 After considering the various policy objectives outlined in the applicable statute, the *Telecommunications Act*, and the purposes set out in the Price Caps Decision, the CRTC concluded that all funds in the deferral accounts should be targeted for disposal by a designated date in 2006:

> The attachment to this Decision provides preliminary estimates of the deferral account balances as of the end of the fourth year of the current price cap period in 2006. <u>The Commission notes that the deferral account balances are expected to be very large for some ILECs. It also notes the concern that allowing funds to continue to accumulate in the accounts would create inefficiencies and uncertainties.</u>
>
> ...
>
> <u>Accordingly, the Commission considers it appropriate not only to provide directions on the disposition of all the funds that will have accumulated in the ILECs' deferral accounts by the end of the fourth year of the price cap period in 2006, but also to provide directions to address amounts recurring beyond this period in order to prevent further accumulation of funds in the deferral accounts.</u> The Commission will provide directions and guidelines for disposing of these amounts later in this Decision. [Emphasis added; paras. 58 and 60.]

14 The CRTC further decided that the deferral accounts should be disbursed primarily for two purposes. As a priority, at least 5 percent of the accounts was to be used for improving accessibility to telecommunications services for individuals with disabilities. The other 95 percent was to be used for broadband expansion in rural and remote communities. Proposals were invited on how the deferral account funds should be applied. If the proposal as approved was for less than the balance of its deferral account, an affected carrier was to distribute the remaining amount to consumers.

15 In summary, therefore, the CRTC decided that the affected carriers should focus on broadband expansion and accessibility improvement. It also decided that if these two objectives could be fulfilled for an amount less than the full deferral account balances, credits to subscribers would be ordered out of the remainder. It should be noted that customers were not to be compensated in proportion to what they had paid through these credits because of the potential administrative complexity of identifying these individuals and quantifying their respective shares. Instead, the credits were to be provided to certain current subscribers. Prospective rate reductions could also be used to eliminate recurring amounts in the accounts.

16 At the time, the balance in the deferral accounts established under the Price Caps Decision was considerable. Bell Canada's account was estimated to contain approximately $480.5 million, while the TELUS account was estimated at about $170 million.

17 It is helpful to set out how the CRTC explained its decision on the allocation of the deferral account funds. Referencing the importance of telecommunications in connecting Canada's "vast geography and relatively dispersed population", it stressed that Canada had fallen behind in the adoption of broadband services (at paras. 73-74). It contrasted the wide availability of broadband service in urban areas with the less developed network in rural and remote communities. Further, it noted that the objectives outlined in the Price Caps Decision and in the *Telecommunications Act* at s. 7(*b*) provided for improving the quality of telecommunications services in those communities, and that their social and economic development would be favoured by an expansion of the national broadband network. In its view, this initiative would also provide a helpful complement to the efforts of both levels of government to expand broadband coverage. It therefore concluded that broadband expansion was an appropriate use of a part of the deferral account funds (at paras. 73-80).

18 The CRTC also explained that while customer credits would be consistent with the objectives set out in s. 7 of the *Telecommunications Act* and with the Price Caps Decision, these disbursements should not be given priority because broadband expansion and accessibility services provided greater long-term benefits. Nevertheless, credits effectively balanced the interests of the "three main stakeholders in the telecommunications markets" (at para. 115), namely customers, competitors and carriers. It concluded that credits did not contradict the purpose of the deferral accounts, and contrasted one-time credits with a reduction of rates. In its view, credits, unlike rate reductions, did not have a sustained negative impact on competition in these markets, which was the concern the deferral accounts were set up to address (at paras. 112-16).

19 A dissenting Commissioner expressed concerns over the disposition of the deferral account funds. In her view, the CRTC had no mandate to direct the expansion of broadband networks across the country. The CRTC's policy had generally been to ensure the provision of a basic level of service, not services like broadband, and she therefore considered the CRTC's reliance on the objectives of the *Telecommunications Act* to be inappropriate.

20 On January 17, 2008, the CRTC issued another decision dealing with the carriers' proposals to use their deferral account balances for the purposes set out in the Deferral Accounts Decision[6]. Some carriers' plans were approved in part, with the result that only a portion of their deferral account balances was allocated to those projects. Consequently, the CRTC required them to submit, by March 25, 2008, a plan for crediting the balance in their deferral accounts to residential subscribers in non-HCSAs.

21 Bell Canada, as well as the Consumers' Association of Canada and the National Anti-Poverty Organization, appealed the CRTC's Deferral Accounts Decision to the Federal Court of Appeal. The Deferral Accounts Decision was stayed by Richard C.J. in the Federal Court of Appeal on January 25, 2008. The decision requiring further submissions on plans to distribute the deferral account balances was also stayed by Sharlow J.A. pending the filing of an application for leave to appeal to this Court on April 23, 2008. Both stay orders were extended by this Court on September 25, 2008. The stay orders do not apply to the funds allocated for the improvement of accessibility for individuals with disabilities.

22 In a careful judgment by Sharlow J.A., the court unanimously dismissed the appeals, concluding that the Price Caps Decision regime always contemplated the future disposition of the deferral account funds as the CRTC would direct, and that the CRTC acted within its broad mandate to pursue its regulatory objectives. For the reasons that follow, I agree with the conclusions reached by Sharlow J.A.

<u>Analysis</u>

23 The parties have staked out diametrically opposite positions on how the balance of the deferral account funds should be allocated.

24 Bell Canada argued that the CRTC had no statutory authority to order what it claimed amounted to retrospective "rebates" to consumers. In its view, the distributions ordered by the CRTC were in substance a variation of rates that had been declared final. TELUS joined Bell Canada in this Court, and argued that the CRTC's order for "rebates" constituted an unjust confiscation of property.

25 In response, the CRTC contended that its broad mandate to set rates under the *Telecommunications Act* includes establishing and ordering the disposal of funds from deferral accounts. Because the deferral account funds had always been subject to the possibility of disbursement to customers, there was therefore no variation of a final rate or any impermissible confiscation.

26 The Consumers' Association of Canada was the only party to oppose the allocation of 5 percent of the deferral account balances to improving accessibility, but abandoned this argument during the hearing before the Federal Court of Appeal. Together with the National Anti-Poverty Organization, it argued before this Court that the rest of the deferral account balances should be distributed to customers in full, and that the CRTC had no authority to allow the use of the funds for broadband expansion.

27 These arguments bring us directly to the statutory scheme at issue.

28 The *Telecommunications Act* lays out the basic legislative framework of the Canadian telecommunications industry. In addition to setting out numerous specific powers, the statute's guiding objectives are set out in s. 7. Pursuant to s. 47(*a*), the CRTC must consider these objectives in the exercise of *all* of its powers. These provisions state:

> **7.** It is hereby affirmed that telecommunications performs an essential role in the maintenance of Canada's identity and sovereignty and that the Canadian telecommunications policy has as its objectives
>
> (*a*) <u>to facilitate the orderly development throughout Canada of a telecommunications system that serves to safeguard, enrich and strengthen the social and economic fabric of Canada and its regions</u>;
>
> (*b*) <u>to render reliable and affordable telecommunications services of high quality accessible to Canadians in both urban and rural areas in all regions of Canada</u>;
>
> (*c*) <u>to enhance the efficiency and competitiveness, at the national and international levels, of Canadian telecommunications</u>;
>
> (*d*) to promote the ownership and control of Canadian carriers by Canadians;

(*e*) to promote the use of Canadian transmission facilities for telecommunications within Canada and between Canada and points outside Canada;

(*f*) to foster increased reliance on market forces for the provision of telecommunications services and to ensure that regulation, where required, is efficient and effective;

(*g*) to stimulate research and development in Canada in the field of telecommunications and to encourage innovation in the provision of telecommunications services;

(*h*) to respond to the economic and social requirements of users of telecommunications services; and

(*i*) to contribute to the protection of the
privacy of persons. ...

47. The Commission shall exercise its powers and perform its duties under this Act and any special Act

(*a*) with a view to implementing the Canadian telecommunications policy objectives and ensuring that Canadian carriers provide telecommunications services and charge rates in accordance with section 27;

The CRTC relied on these two provisions in arguing that it was required to take into account a broad spectrum of considerations in the exercise of its rate-setting powers, and that the Deferral Accounts Decision was simply an extension of this approach.

29 The *Telecommunications Act* grants the CRTC the general power to set and regulate rates for telecommunications services in Canada. All tariffs imposed by carriers, including rates for services, must be submitted to it for approval, and it may decide any matter with respect to rates in the telecommunications services industry, as the following provisions show:

24. The offering and provision of any telecommunications service by a Canadian carrier are subject to any conditions imposed by the Commission or included in a tariff approved by the Commission.

25. (1) No Canadian carrier shall provide a telecommunications service except in accordance with a tariff filed with and approved by the Commission that specifies the rate or the maximum or minimum rate, or both, to be charged for the service.

...

32. The Commission may, for the purposes of this Part,

...

(*g*) in the absence of any applicable provision in this Part, determine any matter and make any order relating to the rates, tariffs or telecommunications services of Canadian carriers.

30 The guiding rule of rate-setting under the *Telecommunications Act* is that the rates be "just and reasonable", a longstanding regulatory principle. To determine whether rates meet this standard, the CRTC has a wide discretion which is protected by a privative clause:

> **27.** (1) Every rate charged by a Canadian carrier for a telecommunications service shall be just and reasonable.
>
> ...
>
> (3) The Commission may determine in any case, as a question of fact, whether a Canadian carrier has complied with section 25, this section or section 29, or with any decision made under section 24, 25, 29, 34 or 40.
>
> ...
>
> (5) In determining whether a rate is just and reasonable, the Commission may adopt any method or technique that it considers appropriate, whether based on a carrier's return on its rate base or otherwise.
>
> ...
>
> **52.** (1) The Commission may, in exercising its powers and performing its duties under this Act or any special Act, determine any question of law or of fact, and its determination on a question of fact is binding and conclusive.

31 In addition to the power under s. 27(5) to adopt "any method or technique that it considers appropriate" for determining whether a rate is just and reasonable, the CRTC also has the authority under s. 37(1) to order a carrier to adopt "any accounting method or system of accounts" in view of the proper administration of the *Telecommunications Act*. Section 37(1) states:

> **37.** (1) The Commission may require a Canadian carrier
>
> (*a*) <u>to adopt any method of identifying the costs of providing telecommunications services and to adopt any accounting method or system of accounts</u> for the purposes of the administration of this Act;

32 The CRTC has other broad powers which, while not at issue in this case, nevertheless further demonstrate the comprehensive regulatory powers Parliament intended to grant. These include the ability to order a Canadian carrier to provide any service in certain circumstances (s. 35(1)); to require communications facilities to be provided or constructed (s. 42(1)); and to establish any sort of fund for the purpose of supporting access to basic telecommunications services (s. 46.5(1)).

33 This statutory overview assists in dealing with the preliminary issue of the applicable standard of review. Although the Federal Court of Appeal accepted the parties' position that the applicable standard of review was correctness, Sharlow J.A. acknowledged that the standard of review could be more deferential in light of this Court's decision in *Council of Canadians with Disabilities v. VIA Rail Canada Inc.*, 2007 SCC 15, [2007] 1 S.C.R. 650, at paras. 98-100. This was an invitation, it seems to me, to clarify what the appropriate standard is.

34 Bell Canada and TELUS concede that the CRTC had the authority to approve disbursements from the deferral accounts for initiatives to improve broadband expansion and accessibility to telecommunications services for persons with disabilities, and that they actually sought such approval. In their view, however, this authority did not extend to what they characterized as retrospective "rebates". Similarly, in the Consumers' appeal the crux of the complaint is with whether the CRTC could direct that the funds be disbursed in certain ways, not with whether it had the authority to direct how the funds ought to be spent generally.

35 This means that for Bell Canada and TELUS appeal, the dispute is over the CRTC's authority and discretion under the *Telecommunications Act* in connection with ordering credits to customers from the deferral accounts. In the Consumers' appeal, it is over its authority and discretion in ordering that funds from the deferral accounts be used for the expansion of broadband services.

36 A central responsibility of the CRTC is to determine and approve just and reasonable rates to be charged for telecommunications services. Together with its rate-setting power, the CRTC has the ability to impose *any* condition on the provision of a service, adopt *any* method to determine whether a rate is just and reasonable and require a carrier to adopt *any* accounting method. It is obliged to exercise all of its powers and duties with a view to implementing the Canadian telecommunications policy objectives set out in s. 7.

37 The CRTC's authority to establish the deferral accounts is found through a combined reading of ss. 27 and 37(1). The authority to establish these accounts necessarily includes the disposition of the funds they contain, a disposition which represents the final step in a process set in motion by the Price Caps Decision. It is self-evident that the CRTC has considerable expertise with respect to this type of question. This observation is reflected in its extensive statutory powers in this regard and in the strong privative clause in s. 52(1) protecting its determinations on questions of fact from appeal, including whether a carrier has adopted a just and reasonable rate.

38 In my view, therefore, the issues raised in these appeals go to the very heart of the CRTC's specialized expertise. In the appeals before us, the core of the quarrel in effect is with the methodology for setting rates and the allocation of certain proceeds derived from those rates, a polycentric exercise with which the CRTC is statutorily charged and which it is uniquely qualified to undertake. This argues for a more deferential standard of review, which leads us to consider whether the CRTC was reasonable in directing how the funds from the deferral accounts were to be used. (See *Dunsmuir v. New Brunswick*, 2008 SCC 9, [2008] 1 S.C.R. 190, at para. 54; *Canada (Citizenship and Immigration) v. Khosa*, 2009 SCC 12, [2009] 1 S.C.R. 339, at para. 25; and *VIA Rail Canada Inc.*, at paras. 88-100.)

39 This brings us to the nature of the CRTC's rate-setting power in the context of this case. The predecessor statute for telecommunications rate-setting, the *Railway Act*, R.S.C. 1985, c. R-3, also stipulated that rates be "just and reasonable" (s. 340(1)). Traditionally, those rates were based on a balancing between a fair rate for the consumer and a fair return on the carrier's investment. (See, e.g., *Northwestern Utilities Ltd. v. City of Edmonton*, [1929] S.C.R. 186, at pp. 192-93 and *ATCO Gas and Pipelines Ltd. v. Alberta (Energy and Utilities Board)*, 2006 SCC 4, [2006] 1 S.C.R. 140, at para. 65.)

40 Even before the expansive language now found in the *Telecommunications Act*, regulatory agencies had enjoyed considerable discretion in determining the factors to be considered and the methodology that could be adopted for assessing whether rates were just and reasonable. For instance, in dismissing a leave application in *Re General Increase in Freight Rates* (1954), 76 C.R.T.C. 12 (S.C.C.), Taschereau J. wrote:

> [I]f the Board is bound to grant a relief which is just to the public and secures to the railways a fair return, it is not bound to accept for the determination of the rates to be charged, the sole method proposed by the applicant. <u>The obligation to act is a question of law, but the choice of the method to be adopted is a question of discretion with which, under the statute, no Court of law may interfere.</u> [Emphasis added; p. 13.]

In making this determination, he relied on Duff C.J.'s judgment in *Canadian National Railways Co. v. Bell Telephone Co. of Canada*, [1939] S.C.R. 308, for the following proposition in the particular statutory context of that case:

> The law dictates neither the order to be made in a given case nor the considerations by which the

> Board is to be guided in arriving at the conclusion that an order, or what order, is necessary or proper in a given case. True, it is the duty of all public bodies and others invested with statutory powers to act reasonably in the execution of them, but the policy of the statue [*sic*] is that, subject to the appeal to the Governor in Council under s. 52, in exercising an administrative discretion entrusted to it, the Board itself is to be the final arbiter as to the order to be made. [p. 315]

(See also Michael H. Ryan, *Canadian Telecommunications Law and Regulation* (loose-leaf ed.), at S.612.)

41 The CRTC's already broad discretion in determining whether rates are just and reasonable has been further enhanced by the inclusion of s. 27(5) in the *Telecommunications Act* permitting the CRTC to adopt "any method", language which was absent from the *Railway Act*.

42 Even more significantly, the *Railway Act* contained nothing analogous to the statutory direction under s. 47 that the CRTC must exercise its rate-setting powers with a view to implementing the Canadian telecommunications objectives set out in s. 7. These statutory additions are significant. Coupled with its rate-setting power, and its ability to use any method for arriving at a just and reasonable rate, these provisions contradict the restrictive interpretation of the CRTC's authority proposed by various parties in these appeals.

43 This was highlighted by Sharlow J.A. when she stated:

> Because of the combined operation of section 47 and section 7 of the *Telecommunications Act* ..., the CRTC's rating jurisdiction is not limited to considerations that have traditionally been considered relevant to ensuring a fair price for consumers and a fair rate of return to the provider of telecommunication services. Section 47 of the *Telecommunications Act* expressly requires the CRTC to consider, as well, the policy objectives listed in section 7 of the *Telecommunications Act*. What that means, in my view, is that in rating decisions under the *Telecommunications Act*, the CRTC is entitled to consider any or all of the policy objectives listed in section 7. [para. 35]

44 It is true that the CRTC had previously used a "rate base rate of return" method, based on a combination of a rate of return for investors in telecommunications carriers and a rate base calculated using the carriers' assets. This resulted in rates charged for the carrier's services that would, on the one hand, provide a fair return for the capital invested in the carrier, and, on the other, be fair to the customers of the carrier.

45 However, these expansive provisions mean that the rate base rate of return approach is not necessarily the only basis for setting a just and reasonable rate. Furthermore, based on ss. 7, 27(5) and 47, the CRTC is not required to confine itself to balancing only the interests of subscribers and carriers with respect to a particular service. In the Price Caps Decision, for example, the CRTC chose to focus on maximum prices for services, rather than on the rate base rate of return approach. It did so, in part, to foster competition in certain markets, a goal untethered to the direct relationship between the carrier and subscriber in the traditional rate base rate of return approach. A similar pricing approach was adopted by the CRTC in a decision preceding the Price Caps Decision[7].

46 The CRTC has interpreted these provisions broadly and identified them as responsive to the evolved industry context in which it operates. In its "Review of Regulatory Framework" decision[8], it wrote:

> <u>The Act ... provides the tools necessary to allow the Commission to alter the traditional manner in which it regulates</u> (i.e., to depart from rate base rate of return regulation).
>
> ...
>
> <u>In brief, telecommunications today transcends traditional boundaries and simple definition.</u> It is an industry, a market and a means of doing business that encompasses a constantly evolving range of voice, data and video products and services.

...

> <u>In this context, the Commission notes that the Act contemplates the evolution of basic service by setting out as an objective the provision of reliable and affordable telecommunications</u>, rather than merely affordable telephone service. [Emphasis added; pp. 6 and 10.]

47 In *Edmonton (City) v. 360Networks Canada Ltd.*, 2007 FCA 106, [2007] 4 F.C.R. 747, leave to appeal refused, [2007], 3 S.C.R. vii, the Federal Court of Appeal drew similar conclusions, observing that the *Telecommunications Act* should be interpreted by reference to the policy objectives, and that s. 7 justified in part the view that the "Act should be interpreted as creating a comprehensive regulatory scheme" (at para. 46). A duty to take a more comprehensive approach was also noted by Ryan, who observed:

> Because of the importance of the telecommunications industry to the country as a whole, rate-making issues may sometimes assume a dimension that gives them a significance that extends beyond the immediate interests of the carrier, its shareholders and its customers, and engages the interests of the public at large. It is also part of the duty of the regulator to take these more far-reaching interests into account. [S.604]

48 This leads inevitably, it seems to me, to the conclusion that the CRTC may set rates that are just and reasonable for the purposes of the *Telecommunications Act* through a diverse range of methods, taking into account a variety of different constituencies and interests referred to in s. 7, not simply those it had previously considered when it was operating under the more restrictive provisions of the *Railway Act*. This observation will also be apposite later in these reasons when the question of "final rates" is discussed in connection with the Bell Canada appeal.

49 I see nothing in this conclusion which contradicts the ratio in *Barrie Public Utilities v. Canadian Cable Television Assn.*, 2003 SCC 28, [2003] 1 S.C.R. 476. In that case, the issue was whether the CRTC could make an order granting cable companies access to certain utilities' power poles. In that decision, the CRTC had relied on the Canadian telecommunications policy objectives to inform its interpretation of the relevant provisions. In deciding that the language of the *Telecommunications Act* did not give the CRTC the power to grant access to the power poles, Gonthier J. for the majority concluded that the CRTC had inappropriately interpreted the Canadian telecommunications policy objectives in s. 7 as power-conferring (at para. 42).

50 The circumstances of *Barrie Public Utilities* are entirely distinct from those at issue before us. Here, we are dealing with the CRTC setting rates that were required to be just and reasonable, an authority fully supported by unambiguous statutory language. In so doing, the CRTC was exercising a broad authority, which, according to s. 47, it was required to do "with a view to implementing the Canadian telecommunications policy objectives ... ". The policy considerations in s. 7 were factors that the CRTC was required to, and did, take into account.

51 Nor does this Court's decision in *ATCO* preclude the pursuit of public interest objectives through rate-setting. In that case, Bastarache J. for the majority, took a strict approach to the Alberta Energy and Utilities Board's powers under the applicable statute. The issue was whether the Board had the authority to order the distribution of proceeds by a regulated company to its subscribers from an asset sale it had approved. It was argued that because the Board had the authority to make "further orders" and impose conditions "in the public interest" on any order, it therefore had the ability to order the disposition of the sale proceeds.

52 In holding that the Board had no such authority, Bastarache J. relied in part on the conclusion that the Board's statutory power to make orders or impose conditions in the public interest was insufficiently precise to grant the ability to distribute sale proceeds to ratepayers (at para. 46). The ability of the Board to approve an asset sale, and its authority to make any order it wished in the public interest, were necessarily limited by the context of the relevant provisions (at paras. 46-48 and 50). It was obliged too to adopt a rate base rate of return method to determine rates, pursuant to its governing statute (at paras. 65-66).

53 Unlike *ATCO*, in the case before us the CRTC's rate-setting authority, and its ability to establish deferral accounts for this purpose, are at the very core of its competence. The CRTC is statutorily authorized to adopt *any* method of determining just and reasonable rates. Furthermore, it is required to consider the statutory objectives in the exercise of its authority, in contrast to the permissive, free-floating direction to consider the public interest that existed in *ATCO*. The *Telecommunications Act* displaces many of the traditional restrictions on rate-setting described in *ATCO*, thereby granting the CRTC the ability to balance the interests of carriers, consumers and competitors in the broader context of the Canadian telecommunications industry (Review of Regulatory Framework Decision, at pp. 6 and 10).

54 The fact that deferral accounts are at issue does nothing to change this framework. No party objected to the CRTC's authority to establish the deferral accounts themselves. These accounts are accepted regulatory tools, available as a part of the Commission's rate-setting powers. As the CRTC has noted, deferral accounts "enabl[e] a regulator to defer consideration of a particular item of expense or revenue that is incapable of being forecast with certainty for the test year"[9]. They have traditionally protected against future eventualities, particularly the difference between forecasted and actual costs and revenues, allowing a regulator to shift costs and expenses from one regulatory period to another. While the CRTC's creation and use of the deferral accounts for broadband expansion and consumer credits may have been innovative, it was fully supported by the provisions of the *Telecommunications Act*.

55 In my view, it follows from the CRTC's broad discretion to determine just and reasonable rates under s. 27, its power to order a carrier to adopt any accounting method under s. 37, and its statutory mandate under s. 47 to implement the wide-ranging Canadian telecommunications policy objectives set out in s. 7, that the *Telecommunications Act* provides the CRTC with considerable scope in establishing and approving the use to be made of deferral accounts. They were created in accordance both with the CRTC's rate-setting authority and with the goal that all rates charged by carriers were and would remain just and reasonable.

56 A deferral account would not serve its purpose if the CRTC did not also have the power to order the disposition of the funds contained in it. In my view, the CRTC had the authority to order the disposition of the accounts in the exercise of its rate-setting power, provided that this exercise was reasonable.

57 I therefore agree with the following observation by Sharlow J.A.:

> The Price Caps Decision required Bell Canada to credit a portion of its final rates to a deferral account, which the CRTC had clearly indicated would be disposed of in due course as the CRTC would direct. There is no dispute that the CRTC is entitled to use the device of a mandatory deferral account to impose a contingent obligation on a telecommunication service provider to make expenditures that the CRTC may direct in the future. <u>It necessarily follows that the CRTC is entitled to make an order crystallizing that obligation and directing a particular expenditure, provided the expenditure can reasonably be justified by one or more of the policy objectives listed in section 7 of the Telecommunications Act.</u> [Emphasis added; para. 52.]

58 This general analytical framework brings us to the more specific questions in these appeals. In the first appeal, Bell Canada relied on Gonthier J.'s decision *Bell Canada v. Canada (Canadian Radio-Television and Telecommunications Commission)*, [1989] 1 S.C.R. 1722 ("*Bell Canada (1989)*"), to argue that "final" rates cannot be changed and that the funds in the deferral accounts could not, therefore, be distributed as "rebates" to customers.

59 In *Bell Canada (1989)*, the CRTC approved a series of interim rates. It subsequently reviewed them in light of Bell Canada's changed financial situation, and ordered the carrier to credit what it considered to be excess revenues to its current subscribers. Arguing against the CRTC's authority to do so, Bell Canada contended that the CRTC could not order a one-time credit with respect to revenues earned from rates approved by the CRTC, whether the rate order was an interim one or not. Gonthier J. observed that while the *Railway Act* contemplated a positive approval scheme that only allowed for prospective, not retroactive or retrospective rate-setting, the one-time credit at issue was nevertheless permissible because the original rates were interim and therefore inherently subject to change.

60 In the current case, Bell Canada argued that the rates had been made final, and that the disposition of the deferral accounts for one-time credits was therefore impermissible. More specifically, it argued that the CRTC's order of one-time credits from the deferral accounts amounted to retrospective rate-setting as the term was used in *Bell Canada (1989)*, at p. 1749, namely, that their "purpose is to remedy the imposition of rates approved in the past and found in the final analysis to be excessive" (at p. 1749).

61 In my view, because this case concerns encumbered revenues in deferral accounts (referred to by Sharlow J.A. as contingent obligations or liabilities), we are not dealing with the variation of final rates. As Sharlow J.A. pointed out, *Bell Canada (1989)* is inapplicable because it was known from the outset in the case before us that Bell Canada would be obliged to use the balance of its deferral account in accordance with the CRTC's subsequent direction (at para. 53).

62 It would, with respect, be an oversimplification to consider that *Bell Canada (1989)* applies to bar the provision of credits to consumers in this case. *Bell Canada (1989)* was decided under the *Railway Act*, a statutory scheme that, significantly, did not include any of the considerations or mandates set out in ss. 7, 27(5) and 47 of the *Telecommunications Act*. Nor did it involve the disposition of funds contained in deferral accounts.

63 In my view, the credits ordered out of the deferral accounts in the case before us are neither retroactive nor retrospective. They do not vary the original rate as approved, which included the deferral accounts, nor do they seek to remedy a deficiency in the rate order through later measures, since these credits or reductions were contemplated as a possible disposition of the deferral account balances from the beginning. These funds can properly be characterized as encumbered revenues, because the rates *always* remained subject to the deferral accounts mechanism established in the Price Caps Decision. The use of deferral accounts therefore precludes a finding of retroactivity or retrospectivity. Furthermore, using deferral accounts to account for the difference between forecast and actual costs and revenues has traditionally been held not to constitute retroactive rate-setting (*EPCOR Generation Inc. v. Energy and Utilities Board*, 2003 ABCA 374, 346 A.R. 281, at para. 12, and *Reference Re Section 101 of the Public Utilities Act* (1998), 164 Nfld. & P.E.I.R. 60 (Nfld. C.A.), at paras. 97-98 and 175).

64 The Deferral Accounts Decision was the culmination of a process undertaken in the Price Caps Decision. In the Price Caps Decision, the CRTC indicated that the amounts in the deferral accounts were to be used in a manner contributing to achieving the CRTC's objectives (at paras. 409 and 412). In the Deferral Accounts Decision, the CRTC summarized its earlier findings that draw-downs could occur for various purposes, including through subscriber credits (at para. 6). When the CRTC approved the rates derived from the Price Caps Decision, the portion of the revenues that went into the deferral accounts remained encumbered. The deferral accounts, and the encumbrance to which the funds recorded in them were subject, were therefore an integral part of the rate-setting exercise ensuring that the rates approved were just and reasonable. It follows that nothing in the Deferral Accounts Decision changed either the Price Caps Decision or any other prior CRTC decision on this point. The CRTC's later allocation of deferral account balances for various purposes, therefore, including customer credits, was not a variation of a final rate order.

65 The allocation of deferral account funds to consumers was not, strictly speaking, a "rebate" in any event. Instead, as in *Bell Canada (1989)*, these allocations were one-time disbursements or rate reductions the carriers were required to make out of the deferral accounts to their *current* subscribers. The possibility of one-time credits was present from the inception of the rate-setting exercise. From the Price Caps Decision onwards, it was understood that the disposition of the deferral account funds might include an eventual credit to subscribers once the CRTC determined the appropriate allocation. It was precisely because the rate-setting mechanism approved by the CRTC included accumulation in and disposition from the deferral accounts pursuant to further CRTC orders, that the rates were and continued to be just and reasonable.

66 Therefore, rather than viewing *Bell Canada (1989)* as setting a strict rule that subscriber credits can never be ordered out of revenues derived from final rates, it is important to remember Gonthier J.'s concern that the financial stability of regulated utilities could be undermined if rates were open to indiscriminate variation (at p. 1760). Nothing in the Deferral Accounts Decision undermined the financial stability of the affected carriers. The amounts at issue were always treated differently for accounting purposes, and the regulated carriers were aware of the fact that the portion of their revenues going into the deferral accounts remained encumbered. In fact, the Price Caps Decision formula would have allowed for *lower* rates than the ones ultimately set, were it not for the creation of the deferral accounts. Those lower rates could conceivably have been considered sufficient to maintain the financial stability of the carriers and were increased only in an effort to encourage market entry by new competitors.

67 TELUS argued additionally that the Deferral Accounts Decision constituted a confiscation of its property. This is an argument I have difficulty accepting. The funds in the accounts never belonged unequivocally to the carriers, and always consisted of encumbered revenues. Had the CRTC intended that these revenues be used for any purposes the affected carriers wanted, it could simply have approved the rates as just and reasonable and ordered the balance of the deferral accounts turned over to them. It chose not to do so.

68 It is also worth noting that in approving Bell Canada's rates, the CRTC ordered it to allocate certain tax savings to the deferral accounts[10]. Neither the CRTC, nor Bell Canada, could possibly have expected that the company would be able to keep that portion of its rate revenue representing a past liability for taxes that it was in fact not currently liable to pay or defer.

69 For the above reasons, I would dismiss the Bell Canada and TELUS appeal.

70 The premise underlying the Consumers' Association of Canada appeal is that the disposition of some deferral account funds for broadband expansion highlighted the fact that the rates charged by carriers were, in a certain sense, not just and reasonable. Consumers can only succeed if it can demonstrate that the CRTC's decision was unreasonable.

71 At its core, Consumers' primary argument was that the Deferral Accounts Decision effectively forced users of a certain service (residential subscribers in certain areas) to subsidize users of another service (the future users of broadband services) once the expansion of broadband infrastructure was completed. In its view, this was an indication that the rates charged to residential users were not in fact just and reasonable, and that therefore the balance in the deferral accounts, excluding the disbursements for accessibility services, should be distributed to customers.

72 As previously noted, the deferral accounts were created and disbursed pursuant to the CRTC's power to approve just and reasonable rates, and were an integral part of such rates. Far from rendering these rates inappropriate, the deferral accounts *ensured* that the rates were just and reasonable. And the policy objectives in s. 7, which the CRTC is always obliged to consider, demonstrate that the CRTC need not limit itself to considering solely the service at issue in determining whether rates are just and reasonable. The statute contemplates a comprehensive national telecommunications framework. It does not require the CRTC to atomize individual services. It is for the CRTC to determine a tolerable level of cross-subsidization.

73 Nor does the traditional approach to telecommunications regulation support Consumers' argument. Long-distance telephone users have long subsidized local telephone users (Price Caps Decision, at para. 2). Therefore, while rates for individual services covered by the *Telecommunications Act* may be evaluated on a just and reasonable basis, rates are not necessarily rendered unreasonable or unjust simply because there is some cross-subsidization between services. (See Ryan, at S.604, for the proposition that the CRTC can determine the appropriate extent of cross-subsidization for a given telecommunications carrier.)

74 In my view, the CRTC properly considered the objectives set out in s. 7 when it ordered expenditures for the expansion of broadband infrastructure and consumer credits. In doing so, it treated the statutory objectives as guiding principles in the exercise of its rate-setting authority. Pursuing policy objectives through the exercise of its rate-setting power is precisely what s. 47 requires the CRTC to do in setting just and reasonable rates.

75 In deciding to allocate the deferral account funds to improving accessibility services and broadband expansion in rural and remote areas, the CRTC had in mind its statutorily mandated objectives of facilitating "the orderly development throughout Canada of a telecommunications system that serves to ... strengthen the social and economic fabric of Canada" under s. 7(*a*); rendering "reliable and affordable telecommunications services ... to Canadians in both urban and rural areas" under s. 7(*b*); and responding "to the economic and social requirements of users of telecommunications services" pursuant to s. 7(*h*).

76 The CRTC heard from several parties, considered its statutorily mandated objectives in exercising its powers, and decided on an appropriate course of action. Under the circumstances, I have no hesitation in holding that the CRTC made a reasonable decision in ordering broadband expansion.

77 I would therefore conclude that the CRTC did exactly what it was mandated to do under the *Telecommunications Act*. It had the statutory authority to set just and reasonable rates, to establish the deferral accounts, and to direct the disposition of the funds in those accounts. It was obliged to do so in accordance with the telecommunications policy objectives set out in the legislation and, as a result, to balance and consider a wide variety of objectives and interests. It did so in these appeals in a reasonable way, both in ordering subscriber credits and in approving the use of the funds for broadband expansion.

78 I would dismiss the appeals. At the request of all parties, there will be no order for costs.

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Solicitors for the respondent MTS Allstream Inc.: Goodmans, Toronto.

Solicitors for the respondent/intervener the Canadian Radio-television and Telecommunications Commission: Torys, Toronto.

1 Telecom Decision CRTC 2002-34.

2 Telecom Decision CRTC 2005-69.

3 Telecom Decision CRTC 2003-15, and Telecom Decision CRTC 2003-18.

4 Telecom Public Notice CRTC 2004-1

5 Telecom Decision CRTC 2006-9.

6 Telecom Decision CRTC 2008-1.

7 Telecom Decision CRTC 97-9.

8 Telecom Decision CRTC 94-19.

9 Telecom Decision CRTC 93-9.

10 Telecom Decision CRTC 2003-15, at para. 32.

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Indexed as:

Bell Canada v. Canada (Canadian Radio-Television and Telecommunications Commission)

The Canadian Radio-Television and Telecommunications Commission, appellant;
v.
Bell Canada, respondent;
and
The Attorney General of Canada, the Consumers' Association of Canada, the Canadian Business Telecommunications Alliance, CNCP Telecommunications and the National Anti-Poverty Organization, interveners.

[1989] 1 S.C.R. 1722

[1989] 1 R.C.S. 1722

[1989] S.C.J. No. 68

1989 CanLII 67

File No.: 20525.

Supreme Court of Canada

1989: February 21 / 1989: June 22.

Present: Lamer, Wilson, La Forest, L'Heureux-Dubé, Sopinka, Gonthier and Cory JJ.

ON APPEAL FROM THE FEDERAL COURT OF APPEAL

Administrative law -- CRTC jurisdiction -- CRTC ordering Bell Canada to grant a one-time credit to its customers -- Order to remedy imposition of interim rates approved by CRTC in 1984 and 1985 and found to be excessive in 1986 -- Whether CRTC had jurisdiction to make such an order -- Whether CRTC's interim rate order may be reviewed in a retrospective manner -- Whether CRTC's power to fix "just and reasonable" rates for Bell Canada involves the regulation of its revenues -- Railway Act, R.S.C., 1985, c. R-3, ss. 335(1), (2), (3), 340(5) -- National Transportation Act, R.S.C., 1985, c. N-20, 52, 60, 66, 68(1).

In March 1984, Bell Canada filed an application with the CRTC for a general rate increase. To prevent a serious deterioration in Bell Canada's financial situation while awaiting the hearing and the final decision on the merits, the CRTC granted Bell Canada an interim rate increase of 2 per cent effective January 1, 1985. The interim rate increase was calculated on the basis of financial information provided by Bell Canada. In its decision, however, the CRTC clearly expressed the intention to review this interim rate increase in its final decision on Bell Canada's application on the basis of complete financial information for the years 1985 and [page1723] 1986. In 1985, given Bell Canada's improved financial situation, the CRTC ordered Bell Canada to file revised tariffs effective as of September 1, 1985. As a result of this decision, Bell Canada was forced to charge the rates effective before its application for a rate increase filed in March 1984. These new rates too were interim in nature. In October 1986, notwithstanding Bell Canada's request to withdraw its initial application for a general rate increase, the CRTC reviewed Bell Canada's financial situation and the appropriateness of its rates. The CRTC established appropriate levels of profitability for Bell Canada on the basis of its return on equity and found that, in 1985 and 1986, it had earned excess revenues for a total of $206 million. Although Bell Canada always charged rates approved by the CRTC, the latter decided that Bell Canada could not retain these excess revenues and ordered it to distribute the excess revenues through a one-time credit to be granted to certain classes of customers. On appeal, the Federal Court of Appeal quashed the CRTC's order. This appeal is to determine (1) whether the CRTC had the legislative authority to review the revenues made by Bell Canada during the period when interim rates were in force; and (2) whether the CRTC had jurisdiction to make an order compelling Bell Canada to grant a one-time credit to its customers.

Held: The appeal should be allowed.

The CRTC's decisions are subject to appeal to the Federal Court of Appeal on questions of law or jurisdiction by virtue of s. 68(1) of the National Transportation Act. Although an appeal tribunal has the right to disagree with the lower tribunal on issues which fall within the scope of the statutory appeal, curial deference should be given to the opinion of the lower tribunal on issues which fall squarely within its area of expertise. Here, Bell Canada is challenging the CRTC's decision on a question of law and jurisdiction involving the nature of interim decisions and the extent of the powers conferred on the CRTC when it makes interim decisions. This question cannot be solved without an analysis of the procedural scheme created by the Railway Act and the National Transportation Act. The decision impugned by Bell Canada is therefore not a decision which falls within the CRTC's area of special expertise and is pursuant to s. 68(1) subject to review in accordance with the principles governing appeals. Indeed, the CRTC was not created for the purpose of interpreting the Railway Act or the National Transportation Act but [page1724] rather to ensure, amongst other duties, that telephone rates are always "just and reasonable".

The fixing of tolls and tariffs that are "just and reasonable" necessarily involves, albeit in a seemingly indirect manner, the regulation of the revenues of the regulated entity as the administrative tribunal must balance the interests of the customers with the necessity of ensuring that the regulated entity is allowed to make sufficient revenues to finance the costs of the services it sells to the public. In fixing fair and reasonable tolls in this case, the CRTC had to take into consideration the level of revenues needed by Bell Canada.

The CRTC had the power to revisit the period during which interim rates were in force. Such power is implied in the power to make interim orders within the statutory scheme established by the Railway Act and the National Transportation Act. It is inherent in the nature of interim orders that their effect as well as any discrepancy between the interim order and the final order may be reviewed and remedied by the final order. It is the interim nature of the order which makes it subject to further retrospective directions. The circumstances under which they are granted also explains and justifies their being, unlike final orders, subject to retrospective review and remedial orders. Interim rate orders dealing in an interlocutory manner with issues which remain to be decided in a final decision are traditionally granted for the purpose of relieving the applicant from the deleterious effects caused by the length of the proceedings. Such decisions are made in an expeditious manner on the basis of evidence which would often be insufficient for the purposes of the final decision. To hold in this case that the interim rates could not be reviewed would not only be contrary to the nature of interim orders, it would also frustrate and subvert the CRTC's order approving interim rates which clearly indicates its intention to review the rates charged for 1985 up to the date of the final decision.

There should be no concern over the financial stability of regulated utility companies where one deals with the power to revisit interim rates. The very purpose of interim rates is to allay the prospect of financial instability which can be caused by the duration of proceedings before a regulatory tribunal. The added flexibility provided by the power to make interim orders is meant to [page1725] foster financial stability throughout the regulatory process. The power to revisit the period during which interim rates were in force is a necessary corollary of this power without which interim orders made in emergency situations may cause irreparable harm and subvert the fundamental purpose of ensuring that rates are just and reasonable.

Even though Parliament has decided to adopt a positive approval regulatory scheme for the regulation of telephone rates, the added flexibility provided by the power to make interim orders indicates that the CRTC is empowered to make orders as of the date at which the initial application was made or as of the date the CRTC initiated the proceedings of its own motion. The power to make interim orders necessarily implies the power to modify in its entirety the rate structure previously established by final order. As a result, the rate review process does not begin at the date of the final hearing; instead, the rate review begins when the CRTC sets interim rates pending a final decision on the merits.

Finally, once it is decided that the CRTC has the power to revisit the period during which interim rates were in force for the purpose of ascertaining whether they were just and reasonable, it follows that it has the power to make a remedial order where, in fact, these rates were not just and reasonable. In any event, s. 340(5) of the Railway Act provides a sufficient statutory basis for the power to make remedial orders including an order to give a one-time credit to certain classes of customers. While the one-time credit order will not necessarily benefit the customers who were actually billed excessive rates, once it is found that the CRTC has the power to make a remedial order, the nature and extent of this order remain within its jurisdiction in the absence of any specific statutory provision on this issue.

Cases Cited

Approved: Re Coseka Resources Ltd. and Saratoga Processing Co. (1981), 126 D.L.R. (3d) 705; referred to: Canadian Union of Public Employees, Local 963 v. New Brunswick Liquor Corp., [1979] 2 S.C.R. 227; Douglas Aircraft Co. of Canada Ltd. v. McConnell, [1980] 1 S.C.R. 245; Alberta Union of Provincial Employees v. Board of Governors of Olds College, [1982] 1 S.C.R. 923; Re Ontario Public Service Employees Union and Forer (1985), 52 O.R. (2d) 705; Re City of Ottawa and Ottawa Professional Firefighters' [page1726] Association, Local 162 (1987), 58 O.R. (2d) 685; Greyhound Lines of Canada Ltd. v. Canadian Human Rights Commission (1987), 78 N.R. 192; Canadian Pacific Ltd. v. Canadian Transport Commission (1987), 79 N.R. 13; British Columbia Electric Railway Co. v. Public Utilities Commission of British Columbia, [1960] S.C.R. 837; Northwestern Utilities Ltd. v. City of Edmonton, [1929] S.C.R. 186; City of Calgary v. Madison Natural Gas Co. (1959), 19 D.L.R. (2d) 655; United States v. Fulton, 475 U.S. 657 (1986); Trans Alaska Pipeline Rate Cases, 436 U.S. 631 (1978); Regina v. Board of Commissioners of Public Utilities (1966), 60 D.L.R. (2d) 703; Re Eurocan Pulp & Paper Co. and British Columbia Energy Commission (1978), 87 D.L.R. (3d) 727; Nova v. Amoco Canada Petroleum Co., [1981] 2 S.C.R. 437.

Statutes and Regulations Cited

CRTC Telecommunications Rules of Procedure, SOR/79-554, Parts III, VII.
National Energy Board Act, R.S.C., 1985, c. N-7, s. 64.
National Transportation Act, R.S.C., 1985, c. N-20, ss. 49, 52, 60(2), 61, 66, 68(1).
Railway Act, R.S.C., 1985, c. R-3, ss. 334 to 340.

APPEAL from a judgment of the Federal Court of Appeal, [1988] 1 F.C. 296, 43 D.L.R. (4th) 30, 78 N.R. 58, quashing an order of the CRTC. Appeal allowed.

Raynold Langlois, Q.C., Greg Van Koughnett, and Luc Huppé, for the appellant.
Gérald R. Tremblay, Q.C., and Michel Racicot, for the respondent.
Graham Garton, for the intervener the Attorney General of Canada.
Janet Yale, for the intervener the Consumer's Association of Canada.
Kenneth G. Engelhart, for the intervener the Canadian Business Telecommunications Alliance.
Michael Ryan, for the intervener CNCP Telecommunications.
Andrew Roman and Robert Horwood, for the intervener the National Anti-Poverty Organization.

Solicitor for the appellant: Avrum Cohen, Hull.
Solicitors for the respondent: Clarkson, Tétrault, Montréal.
Solicitor for the intervener the Attorney General of Canada: The Deputy Attorney General of Canada, Ottawa.
Solicitor for the intervener the Consumers' Association of Canada: Janet Yale, Ottawa.
Solicitor for the intervener Canadian Business Telecommunications Alliance: Kenneth G. Engelhart, Toronto.
Solicitor for the intervener the CNCP Telecommunications: Michael Ryan, Toronto.
Solicitors for the intervener the National Anti-Poverty Organization: Andrew Roman and Glenn W. Bell, Ottawa.
[page1727]

The judgment of the Court was delivered by

1 **GONTHIER J.**:-- The present case is an appeal against a decision of the Federal Court of Appeal which quashed one of the orders made by the appellant in Telecom Decision CRTC 86-17 ("Decision 86-17"). The impugned order compelled the respondent to distribute $206 million in excess revenues earned in the years 1985 and 1986 through a one-time credit to be granted to certain classes of customers. The respondent does not contest the factual findings on which Decision 86-17 is based nor does it claim that this order would unduly prejudice its financial position. None of the other orders made in Decision 86-17 are challenged.

2 The appellant claims that the purpose of the challenged order was to provide telephone users with a remedy against interim rates which turned out to be excessive on the basis of the findings of fact made by the appellant following a final hearing held in the summer of 1986 for the purpose of setting rates to be charged by the respondent in the years 1985 and following. These findings of fact are reported in Decision 86-17. Since this case turns on the proper characterization of the one-time credit order made in Decision 86-17, it is important to describe the procedural history of the administrative proceedings which led to the order now contested by the respondent.

I - The facts

3 On March 28, 1984, the respondent applied for a general rate increase under Part VII of the CRTC Telecommunications Rules of Procedure, SOR/79-554, which provides for a summary public process to deal with special applications. The respondent claimed that the Canadian Government's restraint program restricting rate increases of federally regulated utilities to 5 per cent and 6 per cent was sufficient justification to dispense with the normal procedure for general rate increase applications set out in Part III of the CRTC Telecommunications Rules of Procedure. In Telecom Decision CRTC 84-15, the appellant rejected this application on the ground that the [page1728] respondent had failed to use the appropriate procedure set out in Part III of these rules. However, the appellant indicated that if the respondent was to suffer financial prejudice as a result of the delays involved in preparing for the more complex procedure set out in Part III, it could always apply for interim relief pending a hearing and a decision on the merits (at pp. 8-9):

> The Commission recognizes that, in 1985 and beyond, in the absence of rate relief, a deterioration in the Company's financial position could occur. In this regard, if the Company should find it necessary to file an application for a general rate increase under Part III of the Rules, the Commission would be prepared to schedule a public hearing on such an application in the fall of 1985. Should Bell consider it necessary to seek rate increases to come into effect earlier in 1985 than this schedule would allow, it may of course apply for interim relief. In the event Bell were to seek such interim relief, it would be open to the Company to suggest that the Commission's traditional test for determining interim rate applications is overly restrictive in light of the Commission hearing schedule and to put forward proposals for an alternative test for consideration. [Emphasis added.]

On September 4, 1984, the respondent filed an application for a general rate increase based on 1985 financial data which would come into effect on January 1, 1986. At the same time, the respondent applied for an interim rate increase of 3.6 per cent.

4 In Telecom Decision CRTC 84-28 ("Decision 84-28") rendered on December 19, 1984, the appellant set out the following policy previously adopted in Telecom Decision CRTC 80-7 with respect to the granting of interim rate increases (at pp. 8-9):

> The Commission's policy concerning interim rate increases, enunciated in Decision 80-7, is as follows:
>
>> The Commission considers that, as a rule, general rate increases should only be granted following the full public process contemplated by Part III of its Telecommunications Rules of Procedure. In the absence of such a process, general rate increases should not in the Commission's view be granted, even on an interim [page1729] basis, except where special circumstances can be demonstrated. Such circumstances would include lengthy delays in dealing with an application that could result in a serious deterioration in the financial condition of an applicant absent a general interim increase. [Emphasis added.]

The respondent argued that its financial situation warranted an interim rate increase and did not question the reasonableness of this policy. The appellant agreed with the respondent's submission that, in the absence of interim rate increases, it might suffer from serious financial deterioration and awarded an interim rate increase of 2 per cent. In this decision, the appellant required the respondent to prepare for a hearing to be held in the fall of 1985 for the purpose of assessing the respondent's application for a final order increasing its rates on the basis of two test years, 1985 and 1986. Decision 84-28 also states at p. 10 the reasons why the interim rate increase was set at 2 per cent:

> In determining the amount of interim rate increases required under the circumstances, the Commission has taken into account the following factors:
>
> 1) While the company stated that an interest coverage ratio of 4.0 times is required, the Commission regards the maintenance of the coverage ratio of 3.8 times, projected by the Company for 1984, as sufficient for the purposes of this interim decision.
> 2) With regard to the level of ROE ["return on equity"], the Commission is of the view that, for 1985, and subject to review in the course of its consideration of the Company's general rate increase application in the fall of 1985, 13.7% is appropriate for determining the amount of rate increases to be permitted pursuant to this interim increase application.
> 3) With regard to the Company's 1985 expense forecasts, the Commission notes that the inflation factor used by the Company is higher than the current consensus forecast of the

> inflation rate for 1985 and considers that Bell's forecast of its 1985 Operating Expenses could be overestimated by approximately $25 million.

[page1730]

> Taking the above factors into account, the Commission has decided that an interim rate increase of 2% for all services in respect of which rate increases were requested by the Company in the interim application is appropriate at this time. This increase is expected to generate additional revenues of $65 million from 1 January 1985 to 31 December 1985. To permit the review of the Company's 1985 revenue requirement by the Commission at the fall 1985 public hearing, Bell is directed to file its 4 June 1985 general rate increase application on the basis of two test years, 1985 and 1986. [Emphasis added.]

The reasons set out in the appellant's decision indicate that the interim rate increase was calculated on the basis of financial information provided by the respondent without placing this information under the scrutiny normally associated with hearings made under Part III of the CRTC Telecommunications Rules of Procedure. Furthermore, the appellant clearly expressed the intention to review this interim rate increase in its final decision on the respondent's application for a general rate increase on the basis of financial information for the years 1985 and 1986. Given the content of the appellant's final decision, it is also important to note that the 2 per cent interim rate increase was calculated on the assumption that the respondent's return on equity for 1985 should be 13.7 per cent, subject to review in the final decision.

5 The respondent's financial situation later improved thereby reducing the necessity to proceed with an early hearing for the purpose of obtaining a general and final rate increase. By letter dated March 20, 1985, the respondent asked for this hearing to be postponed to February 10, 1986, suggesting however that the 2 per cent interim increase be given immediate final approval. In CRTC Telecom Public Notice 1985-30 dated April 16, 1985, the appellant granted the postponement but refused to grant the final approval requested by the respondent without further investigation into this matter. The Commission added that it would monitor the respondent's [page1731] financial situation on a monthly basis and ordered the filing of monthly statements (at p. 4):

> In view of the improving trend in the Company's financial performance, the Commission further directs as follows:
>
> Bell Canada is to provide to the Commission for the balance of 1985, within 30 days after the end of each month, commencing with April 1985, a full year forecast of revenues and expenses on a regulated basis for the year 1985, together with the estimated financial ratios including the projected regulated return on common equity.
>
> The Commission will monitor the Company's financial performance during 1985, in order to determine whether any further rate action may be necessary. [Emphasis added.]

Again, the appellant clearly expressed its intention to prevent abuse of interim rate increases.

6 After a review of the July financial information filing ordered in CRTC Telecom Public Notice 1985-30, the appellant asked the respondent to provide reasons why the interim rate increase of 2 per cent should remain in force given its improved financial situation. The respondent was unable to convince the appellant that this interim increase remained necessary to avoid financial deterioration and was accordingly ordered to file revised tariffs effective as of September 1, 1985, at pp. 4-5 of Telecom Decision CRTC 85-18:

> In view of the improving trend in Bell's financial performance, the Commission is satisfied that the company no longer needs the 2% interim increases which were awarded in Decision 84-28 in order to avoid serious financial deterioration in 1985. Accordingly, Bell is directed to file revised tariffs forthwith, with an effective date of 1 September 1985, to suspend these increases.
>
> In arriving at its decision the Commission has estimated that, with interim rates in effect for the complete year, the company would earn an ROE ["return on equity"] of approximately 14.5% in 1985, a return well in excess of the 13.7% considered appropriate for determining the 2% interim rate increases. The Commission also projected that interest coverage would be approximately 3.9 times. This would improve on the actual 1984 coverage [page1732] of 3.8 times. These estimates are not significantly different from Bell's current expectation of its 1985 results.
>
> The Commission will make its final determination of Bell's revenue requirement for the year 1985 in the general rate proceeding currently scheduled to commence with an application to be filed on 10 February 1986. [Emphasis added.]

As a result of this decision, the respondent was forced to charge the rates effective before its application for a rate increase filed on March 28, 1984. However, even though the rates effective as of September 1, 1985, were numerically identical to the rates in force under the previous final decision prior to the interim increase, these new rates remained interim in nature. In fact, the appellant reiterated its intention to review the rates actually charged during 1985 and 1986.

7 On October 31, 1985, the respondent decided not to proceed with its application for a general rate increase and requested that its procedures be withdrawn. In CRTC Telecom Public Notice 1985-85, the appellant decided to review the respondent's financial situation and therefore the appropriateness of its rates notwithstanding its request to withdraw its initial application for a general rate increase (at pp. 3-4):

> In light of these forecasts and the degree to which the company's rate structure is expected to be considered in separate proceedings, Bell stated that it wished to refrain from proceeding with the application scheduled to be filed on 10 February 1986. Accordingly, the company requested the withdrawal of the amended Directions on Procedure issued by the Commission in Public Notice 1985-30.
>
> . . .
>
> The Commission notes that the appropriate rate of return for Bell has not been reviewed in an oral hearing since the proceeding which culminated in Bell Canada - General Increase in Rates, Telecom Decision CRTC 81-15, 20 September 1981 (Decision 81-15). The Commission considers that, given Bell's current forecasts, it would be appropriate to review the company's cost of equity for the years 1985, 1986 and 1987 in the proceeding scheduled for 1986. Such a review would allow consideration of the changing financial and economic [page1733] conditions since Decision 81-15 and the impact of Bell's corporate reorganization on its rate of return. The Commission notes that other issues arising from the reorganization would also be addressed in the 1986 proceeding. [Emphasis added.]

This interim decision indicates that the appellant wished to continue the original rate review procedure initiated by the respondent in March of 1984. Thus, the rates in force as of January 1, 1985 until the final decision now challenged by the respondent were interim rates subject to review.

8 The hearing which led to the final decision lasted from June 2 to July 16, 1986 and this final decision, Decision 86-17, was rendered on October 14, 1986. In this decision, the appellant first established appropriate levels of profitability for the respondent on the basis of its return on equity. The appellant then calculated the amount of excess revenues earned by the respondent in 1985 and 1986 along with the necessary reduction in forecasted revenues for 1987. It was found that the respondent had earned excess revenues of $63 million in 1985 and $143 million in 1986 for a total of $206 million (at p. 93):

> After making further adjustments for the compensation for temporarily transferred employees and including the regulatory treatment for non-integral subsidiary and associated companies, the Commission has determined that a revenue requirement reduction of $234 million would provide the company with a 12.75% ROE ["return on equity"] on a regulated basis in 1987. Similarly, the Commission has determined that $143 million is the required revenue reduction to achieve the upper end of the permissible ROE on a regulated basis in 1986, 13.25%.
>
> With respect to 1985, after making the adjustments set out in this decision, the Commission has determined that Bell earned excess revenues in the amount of $63 million, the deduction of which would provide 13.75%, the upper end of the permissible ROE on a regulated basis.

[page1734]

It is important to note that the evidence and the arguments presented by the interested parties as well as interveners were carefully scrutinized by the appellant at pp. 77 to 92 of Decision 86-17. It is for all practical purposes impossible to engage in such a meticulous and painstaking analysis of all relevant facts when faced with an application for interim relief. Finally, it is also useful to note that the permissible return on equity of 13.7 per cent allowed by the appellant in its interim decision, Decision 84-28, was increased to 13.75 per cent in Decision 86-17. Thus, the appellant realized that the interim rates approved for 1985 yielded greater rates of return than initially anticipated and that the rate of return actually recorded for that year even exceeded the greater allowable rate of return fixed in the final decision, Decision 86-17. Such differences between projected and actual rates of return are common and certainly call for a high level of flexibility in the exercise of the appellant's regulatory duties.

9 The Commission decided that the respondent could not retain excess revenues earned on the basis of interim rates and issued the order now challenged by the respondent in order to provide a remedy for this situation. This order reads as follows, at pp. 95-96:

> Concerning the excess revenues for the years 1985 and 1986, the Commission directs that the required adjustments be made by means of a one-time credit to subscribers of record, as of the date of this decision, of the following local services: residence and business individual, two-party and four-party line services; PBX trunk services; centrex lines; enhanced exchange-wide dial lines; exchange radio-telephone service; service-system service and information system access line service. The Commission directs that the credit to each subscriber be determined by pro-rating the sum of the excess revenues for 1985 and 1986 of $206 million in relation to the subscriber's monthly recurring billing for the specified local services provided as of the date of this decision. The Commission further directs that the work necessary to implement the above directives be commenced immediately and that the billing adjustments be completed by no later than 31 January 1987. Finally, the Commission directs the company to file a report detailing [page1735] the implementation of the credit by no later than 16 February 1987.

> The Commission considers that 1987 excess revenues are best dealt with through rate reductions to be effective 1 January 1987. [Emphasis added.]

Although the respondent always charged rates approved by the appellant, the appellant found it necessary to make sure that its assessment of allowable revenues for 1985 and 1986 would be complied with. The appellant argues that the order now challenged by the respondent was the most efficient way of redistributing these excess revenues to the respondent's customers even though they would not necessarily be refunded to those who actually had to pay the rates in force during that period.

10 It is therefore obvious that the appellant only allowed interim rates to be charged after January 1, 1985 on the assumption that it would review these rates in a hearing to be held in order to deal with an application for a general rate increase. Every interim decision which led to Decision 86-17 confirmed the appellant's intention to review the interim rates at the final hearing. Finally, the interim rates were ordered for the purpose of preventing any serious deterioration in the respondent's financial situation while awaiting for a final decision on the merits. Of necessity, these interim rates were determined on the basis of incomplete evidence presented by the respondent. It cannot be said that the purpose of the interim rate increase ordered by the appellant was to serve as a temporary final decision.

II - The Issue and the Arguments Raised by the Parties

11 In this Court as well as in the Federal Court of Appeal, the parties have agreed that the only issue arising out of the facts of this case is whether the appellant had jurisdiction to order the respondent to grant a one-time credit to its customers. The appellant's findings of fact, its determination with respect to the respondent's revenue requirements for 1985 and 1986 and its computation of the [page1736] amount of excess revenues earned during this period are not contested by the respondent. In my opinion, this issue can be divided in two sub-questions:

1- whether the appellant had the legislative authority to review the revenues made by the respondent during the period when interim rates were in force;

2- whether the appellant had jurisdiction to make an order compelling the respondent to grant a one-time credit to its customers.

12 The main arguments raised by the appellant can be summarized as follows:

1- the Railway Act and the National Transportation Act grant the appellant the power to review the period during which a regulated entity was allowed to charge interim rates for the purpose of comparing the revenues earned during this period to the appropriate level of revenues set in the final decision;

2- the power to make a one-time credit order is necessarily ancillary to the power to review the period during which interim rates were charged and the appellant has jurisdiction to determine the most efficient method of providing a remedy in cases where excess revenues were made.

13 The main arguments raised by the respondent can be summarized as follows:

1- the power to set tolls and tariffs does not include the power to review and make orders with respect to the respondent's level of revenues;

2- the appellant has no power to make a one-time credit order with respect to revenues earned as a result of having charged rates which the respondent, by virtue of the Railway Act, was obliged to charge, whether these rates were set by interim order or by a final order.

14 Counsel for the National Anti-Poverty Organization ("NAPO") has also argued that the appellant's [page1737] decisions concerning the interpretation of statutes which grant them jurisdiction to deal with certain matters are entitled to curial deference and cannot be reviewed unless they are patently unreasonable. This argument raises the issue of the scope of review allowed by s. 68(1) of the National Transportation Act, R.S.C., 1985, c. N-20, (now the National Telecommunications Powers and Procedures Act), and must be dealt with prior to any analysis of the relevant statutory provisions claimed to be the source of the appellant's jurisdiction to make the one-time credit order found in Decision 86-17.

15 The present case raises difficult questions of statutory interpretation and it will therefore be necessary to examine the relevant provisions of the Railway Act, R.S.C., 1985, c. R-3, and the National Transportation Act before moving to a detailed analysis of the decision of the Federal Court of Appeal and the arguments raised by the parties.

III - Relevant Legislative Provisions

16 The appellant derives its power to regulate the telephone industry from ss. 334 to 340 of the Railway Act ("Provisions Governing Telegraphs and Telephones") and from ss. 47 et seq. of the National Transportation Act ("General Jurisdiction and Powers in Respect of Railways"). The Railway Act sets out the general criteria concerning the setting of rates and tariffs to be charged by telephone utility companies whereas the National Transportation Act sets out the appellant's procedural powers in the context of decisions concerning, amongst other matters, telephone rates and tariffs.

17 Sections 335(1), 335(2) and 335(3) of the Railway Act (formerly ss. 320(2) and 320(3)) state the principle upon which the appellant's regulatory authority rests, namely that telephone rates and tariffs are subject to approval by the appellant, cannot be changed without its prior authorization and may be revised at any time by the appellant:

[page1738]

> 335. (1) Notwithstanding anything in any other Act, all telegraph and telephone tolls to be charged by a company, other than a toll for the transmission of a message intended for reception by the general public and charged by a company licensed under the Broadcasting Act, are subject to the approval of the Commission, and may be revised by the Commission from time to time.
>
> (2) The company shall file with the Commission tariffs of any telegraph or telephone tolls to be charged, and the tariffs shall be in such form, size and style, and give such information, particulars and details, as the Commission by regulation or in any particular case prescribes.
>
> (3) Except with the approval of the Commission, the company shall not charge and is not entitled to charge any telegraph or telephone toll in respect of which there is default in filing

> under subsection (2), or which is disallowed by the Commission ... [Emphasis added.]

The most important requirement governing the appellant's power to set telephone rates is found in s. 340(1) of the Railway Act which provides that all such rates must be "just and reasonable":

> 340. (1) All tolls shall be just and reasonable and shall always, under substantially similar circumstances and conditions with respect to all traffic of the same description carried over the same route, be charged equally to all persons at the same rate. [Emphasis added.]

Section 340 also prohibits discriminatory telephone rates and gives the appellant the power to suspend, postpone, or disallow a tariff of tolls which is contrary to ss. 335 to 340 and substitute a satisfactory tariff of tolls in lieu thereof.

18 Finally, s. 340(5) of the Railway Act gives the appellant the power to make orders with respect to traffic, tolls and tariffs in all matters not expressly covered by s. 340:

> 340. ...
>
> (5) In all other matters not expressly provided for in this section, the Commission may make orders with respect to all matters relating to traffic, tolls and tariffs or any of them.

Although the power granted by s. 340(5) could be construed restrictively by the application of the [page1739] ejusdem generis rule, I do not think that such an interpretation is warranted. Section 340(5) is but one indication of the legislator's intention to give the appellant all the powers necessary to ensure that the principle set out in s. 340(1), namely that all rates should be just and reasonable, be observed at all times.

19 Sections 47 et seq. of the National Transportation Act set out, from a procedural point of view, the appellant's jurisdiction with respect to the powers granted by the Railway Act. Section 49(1) gives the appellant jurisdiction over all complaints concerning compliance with the Act while s. 49(3) gives the appellant jurisdiction over all matters of fact or law for the purposes of the Railway Act and of ss. 47 et seq. of the National Transportation Act. However, s. 68(1) provides an appeal to the Federal Court of Appeal, with leave, on any question of law or jurisdiction and it is under this provision that the respondent has challenged Decision 86-17.

20 In many respects, ss. 47 et seq. of the National Transportation Act have been designed to further the policy objectives and the regulatory scheme set out in the Railway Act governing the approval of telephone rates and tariffs. Thus, s. 52 of the National Transportation Act gives the appellant the power to inquire into, hear or determine, of its own motion or upon request from the Minister, any matter which it has the right to inquire into, hear or determine under the Railway Act:

> 52. The Commission may, of its own motion, or shall, on the request of the Minister, inquire into, hear and determine any matter or thing that, under this part or the Railway Act, it may inquire into, hear and determine upon application or complaint, and with respect thereto has the same powers as, on any application or complaint, are vested in it by this Act.

Section 52 is therefore the corollary of the appellant's power to "revise [tolls] ... from time to time" found in s. 335(1) of the Railway Act. Thus, the appellant has the power to review, from time to [page1740] time, its own final decisions on a proprio motu basis. Similarly, s. 61 provides that the appellant is not bound by the wording of any complaint or application it hears and may make orders which would otherwise offend the ultra petita rule:

> 61. On any application made to the Commission, the Commission may make an order granting the whole or part only of the application, or may grant such further or other relief, in addition to or in substitution for that applied for, as to the Commission may seem just and proper,

as fully in all respects as if the application had been for that partial, other or further relief.

21 By virtue of s. 60(2) of the National Transportation Act, the appellant also has the power to make interim orders:

60. ...

(2) The Commission may, instead of making an order final in the first instance, make an interim order and reserve further directions either for an adjourned hearing of the matter or for further application.

22 Finally, by virtue of s. 66 of the National Transportation Act, the appellant has the power to review any of its past decisions whether they are final or interim:

66. The Commission may review, rescind, change, alter or vary any order or decision made by it or may re-hear any application before deciding it.

23 It is obvious from the legislative scheme set out in the Railway Act and the National Transportation Act that the appellant has been given broad powers for the purpose of ensuring that telephone rates and tariffs are, at all times, just and reasonable. The appellant may revise rates at any time, either of its own motion or in the context of an application made by an interested party. The appellant is not even bound by the relief sought by such applications and may make any order related thereto provided that the parties have received adequate notice of the issues to be dealt with at the hearing. Were it not for the fact that the appellant has the power to make interim orders, one might say that the appellant's powers in this area are limited only by the time it takes to process applications, [page1741] prepare for hearings and analyse all the evidence. However, the appellant does have the power to make interim orders and this power must be interpreted in light of the legislator's intention to provide the appellant with flexible and versatile powers for the purpose of ensuring that telephone rates are always just and reasonable.

24 The question before this Court is whether the appellant has the statutory authority to make a one-time credit order for the purpose of remedying a situation where, after a final hearing dealing with the reasonableness of telephone rates charged during the years under review, it finds that interim rates in force during that period were not just and reasonable. Since there is no clear provision on this subject in the Railway Act or in the National Transportation Act, it will be necessary to determine whether this power is derived by necessary implication from the regulatory schemes set out in these statutes.

IV - The Decision of the Court Below

25 In the Federal Court of Appeal, the respondent in this Court argued that in order to find statutory authority for the power to make a one-time credit order, it was necessary to find that s. 66 (power to "review, rescind, change, alter or vary" previous decisions) or s. 60(2) (power to make interim orders) of the National Transportation Act provide powers to make retroactive orders. Of course, the respondent argued that these provisions did not grant such a power and the majority of the Federal Court of Appeal composed of Marceau and Pratte JJ. agreed with this argument, Hugessen J. dissenting.

26 Marceau J. held that the appellant in this Court only had the power to fix telephone tolls and tariffs and that it has no statutory authority to deal with excess revenues or deficiencies in revenues arising as a result of a discrepancy between the rate of return yielded from the interim rates in force prior to the final decision and the permissible rate of return fixed by this final decision. Marceau J. was of the opinion that the wording of s. 66 of the National Transportation Act is neutral with [page1742] respect to retroactivity and that the presumption against retroactivity should therefore operate. Marceau J. added that the power to make interim orders does not carry with it the power to remedy any discrepancy between interim and final orders because the respondent could not be forced to reimburse revenues earned by charging rates approved by the appellant. Thus, according to Marceau J., the regulatory scheme set out in the Railway Act and the National Transportation Act is prospective in nature and, in the context of such a scheme, the power to make interim orders only involves the power to make orders "for the time being".

27 Pratte J., who concurred in the result with Marceau J., rejected all arguments based on the retroactive nature of the powers granted by ss. 60(2) and 66 of the National Transportation Act. Pratte J. was of the opinion that the impugned order was not retroactive in nature since its effect was to force the respondent to grant a credit in the future rather than change the rates charged in the past in a retroactive manner. Pratte J. then stated that if legislative authority existed for Decision 86-17, it must be found in s. 60(2) of the National Transportation Act which provides for "further directions" to be made at a later date following an interim decision. However, Pratte J. was of the opinion that any "further direction" must be in the nature of an order which can be made under s. 60(2) in the first place. It follows from that reasoning that if no one-time credit order can be made by interim order, no "further direction" to that effect can be made under s. 60(2). Pratte J. then agreed with Marceau J. that the respondent could not be forced to reimburse revenues made by charging rates approved by the appellant whether by interim order or by a "further direction" made in a final order.

28 Hugessen J. dissented on the basis that, within the statutory framework set out in the Railway Act and the National Transportation Act, all [page1743] orders whether final or interim can, by virtue of ss. 60(2) and 66 of the National Transportation Act, be modified by a further prospective order; thus, the proposed rule that interim orders can only be modified by a further prospective order would, in Hugessen J.'s opinion, effectively eliminate any distinction between final and interim orders and defeat the legislator's intention to provide the appellant with a distinct and independent power to make interim orders. In order to differentiate interim orders from final orders, Hugessen J. was of the opinion that the appellant in this Court must have the power to fix just and reasonable rates as of the date at which interim rates came into effect. Thus, only interim rates can be modified in a retrospective manner by a final order. Hugessen J. then stated that the interim rates in force in 1985 and 1986 must not be divided into the previous rate and the interim rate increase of 2 per cent: the resulting rate must be viewed as interim in its entirety because all the rates charged after January 1, 1985 were authorized by interim orders. Finally, Hugessen J. stated that the one-time credit order was a valid exercise of the power to set just and reasonable rates as of January 1, 1985 and that the choice of the appropriate remedy was an "'administrative matter' properly left for the Commission's determination". Hugessen J. also noted that the appellant's order was in substance though not in form a "matter relating to tolls and tariffs" within the meaning of s. 340(5) of the Railway Act.

V - Analysis

(A) Curial Deference Towards the Decisions of the CRTC

29 NAPO argues that the appellant's decisions are entitled to "curial deference" because of their national importance and that these decisions should not be overturned unless they are patently unreasonable. NAPO cites the following cases as [page1744] authority for this proposition: Canadian Union of Public Employees, Local 963 v. New Brunswick Liquor Corp., [1979] 2 S.C.R. 227 ("CUPE"); Douglas Aircraft Co. of Canada Ltd. v. McConnell, [1980] 1 S.C.R. 245; Alberta Union of Provincial Employees v. Board of Governors of Olds College, [1982] 1 S.C.R. 923; Re Ontario Public Service Employees Union and Forer (1985), 52 O.R. (2d) 705 (C.A.); Re City of Ottawa and Ottawa Professional Firefighters' Association, Local 162 (1987), 58 O.R. (2d) 685 (C.A.); Greyhound Lines of Canada Ltd. v. Canadian Human Rights Commission (1987), 78 N.R. 192 (F.C.A.); and Canadian Pacific Ltd. v. Canadian Transport Commission (1987), 79 N.R. 13 (F.C.A.) ("Canadian Pacific").

30 With the exception of the Canadian Pacific case, all these cases involved judicial review of decisions which were either protected by a privative clause or by a provision stating that no appeal lies therefrom. Where the legislator has clearly stated that the decision of an administrative tribunal is final and binding, courts of original jurisdiction cannot interfere with such decisions unless the tribunal has committed an error which goes to its jurisdiction. Thus, this Court has decided in the CUPE case that judicial review cannot be completely excluded by statute and that courts of original jurisdiction can always quash a decision if it is "so patently unreasonable that its construction cannot be rationally supported by the relevant legislation and demands intervention by the court upon review" (p. 237). Decisions which are so protected are, in that sense, entitled to a non-discretionary form of deference because the legislator intended them to be final and conclusive and, in turn, this intention arises out of the desire to leave the resolution of some issues in the hands of a specialized tribunal. In the CUPE case, Dickson J., as he then was, described the legislator's intention as follows, at pp. 235-36:

> Section 101 constitutes a clear statutory direction on the part of the Legislature that public sector labour matters be promptly and finally decided by the Board. Privative clauses of this type are typically found in labour relations [page1745] legislation. The rationale for protection of a labour board's decisions within jurisdiction is straightforward and compelling. The labour board is a specialized tribunal which administers a comprehensive statute regulating labour relations. In the administration of that regime, a board is called upon not only to find facts and decide questions of law, but also to exercise its understanding of the body of jurisprudence that has developed around the collective bargaining system, as understood in Canada, and its labour relations sense acquired from accumulated experience in the area.

However, it is important to stress the fact that the decision of an administrative tribunal can only be entitled to such deference if the legislator has clearly expressed his intention to protect such decisions through the use of privative clauses or clauses which state that the decision is final and without appeal. As formulated, NAPO's argument on curial deference must therefore be rejected because it fails to recognize the basic difference between appellate review and judicial review of decisions which do not fall within the jurisdiction of the lower tribunal.

31 Although s. 49(3) of the National Transportation Act provides that the appellant has full jurisdiction to hear and determine all matters whether of law or fact for the purposes of the Railway Act and of Part IV of the National Transportation Act, the appellant's decisions are subject to appeal, with leave, to the Federal Court of Appeal on questions of law or jurisdiction by virtue of s. 68(1) which reads as follows:

> 68. (1) An appeal lies from the Commission to the Federal Court of Appeal on a question of law or a question of jurisdiction on leave therefor being obtained from that Court on application made within one month after the making of the order, decision, rule or regulation sought to be appealed from or within such further time as a judge of that Court under special circumstances allows, and on notice to the parties and the Commission, and on hearing such of them as appear and desire to be heard.

It is trite to say that the jurisdiction of a court on appeal is much broader than the jurisdiction of a court on judicial review. In principle, a court is [page1746] entitled, on appeal, to disagree with the reasoning of the lower tribunal.

32 However, within the context of a statutory appeal from an administrative tribunal, additional consideration must be given to the principle of specialization of duties. Although an appeal tribunal has the right to disagree with the lower tribunal on issues which fall within the scope of the statutory appeal, curial deference should be given to the opinion of the lower tribunal on issues which fall squarely within its area of expertise. The Canadian Pacific case is an example of a situation where curial deference towards a decision of the Canadian Transport Commission involving the interpretation of a tariff was appropriate. The decision of the Canadian Transport Commission was appealed to a review committee and then to the Federal Court of Appeal. Urie J. held that the decision of the review committee must not be reversed unless it is unreasonable or clearly wrong, at pp. 16-17:

> On the appeal from that decision to this court, the appellant advanced essentially the same grounds and arguments which it had submitted to the RTC. As to the first ground, I am of the opinion that the RTC correctly interpreted the two items from the tariff and since its view was confirmed by the Review Committee, that committee did not commit an error in construction. No useful purpose would be served by my restating the reasons of the R.T.C. for interpreting the items as they did and I respectfully adopt them as my own. This Court should not interfere with

> an interpretation made by bodies having the expertise of the R.T.C. and the Review Committee in an area within their jurisdiction, unless their interpretation is not reasonable or is clearly wrong. Neither situation prevails in this case. [Emphasis added.]

Although the very purpose of the review committee is to interpret the tariff and although such questions of interpretation fall within the Review Committee's area of special expertise, it does not follow that its decisions can only be reviewed if they are unreasonable. However the principle of specialization of duties justifies curial deference in such circumstances.

[page1747]

33 In this case, the respondent is challenging the appellant's decision on a question of law and jurisdiction involving the nature of interim decisions and the extent of the powers conferred on the appellant when it makes interim decisions. This question cannot be solved without an analysis of the procedural scheme created by the Railway Act and the National Transportation Act. It is a question of law which is clearly subject to appeal under s. 68(1) of the National Transportation Act. It is also a question of jurisdiction because it involves an inquiry into whether the appellant had the power to make a one-time credit order.

34 Except as regards the choice, amongst remedies available to the appellant, of the most appropriate remedy to achieve the goal of just and reasonable rates throughout the interim period, the decision impugned by the respondent is not a decision which falls within the appellant's area of special expertise and is therefore pursuant to s. 68(1) subject to review in accordance with the principles governing appeals. Indeed, the appellant was not created for the purpose of interpreting the Railway Act or the National Transportation Act but rather to ensure, amongst other duties, that telephone rates are always just and reasonable.

(B) The Power to Regulate Bell Canada's Revenues

35 The respondent argues that the appellant only has jurisdiction to regulate tolls and tariffs and that this power does not include the power to regulate its level of revenues or its return on equity.

36 The fixing of tolls and tariffs that are just and reasonable necessarily involves the regulation of the revenues of the regulated entity. This has been recognized by this Court interpreting provisions similar to s. 340(1) of the Railway Act which prescribe that "[a]ll tolls shall be just and reasonable". In British Columbia Electric Railway Co. v. Public Utilities Commission of British Columbia, [1960] S.C.R. 837, Locke J. said the following about para. 16(1)(b) of the Public Utilities Act, R.S.B.C. 1948, c. 277, which provided that in [page1748] fixing a rate the Public Utility Commission of British Columbia should take into consideration the "fair and reasonable return upon the appraised value of the property of the public utility used ... to enable the public utility to furnish the service" (at p. 848):

> I do not think it is possible to define what constitutes a fair return upon the property of utilities in a manner applicable to all cases or that it is expedient to attempt to do so. It is a continuing obligation that rests upon such a utility to provide what the Commission regards as adequate service in supplying not only electricity but transportation and gas, to maintain its properties in a satisfactory state to render adequate service and to provide extensions to these services when, in the opinion of the Commission, such are necessary. In coming to its conclusion as to what constituted a fair return to be allowed to the appellant these matters as well as the undoubted fact that the earnings must be sufficient, if the company was to discharge these statutory duties, to enable it to pay reasonable dividends and attract capital, either by the sale of shares or securities, were of necessity considered. Once that decision was made it was, in my opinion, the duty of the Commission imposed by the statute to approve rates which would enable

> the company to earn such a return or such lesser return as it might decide to ask. [Emphasis added.]

In Northwestern Utilities Ltd. v. City of Edmonton, [1929] S.C.R. 186, Lamont J. described the relevant factors in the determination of what are just and reasonable rates as follows (at p. 190):

> In order to fix just and reasonable rates, which it was the duty of the Board to fix, the Board had to consider certain elements which must always be taken into account in fixing a rate which is fair and reasonable to the consumer and to the company. One of these is the rate base, by which is meant the amount which the Board considers the owner of the utility has invested in the enterprise and on which he is entitled to a fair return. Another is the percentage to be allowed as a fair return.

Such provisions require the administrative tribunal to balance the interests of the customers with the necessity of ensuring that the regulated entity is allowed to make sufficient revenues to finance the costs of the services it sells to the public.

[page1749]

37 Thus, it is trite to say that in fixing fair and reasonable tolls the appellant must take into consideration the level of revenues needed by the respondent. In fact, the respondent would be the first to complain if its financial situation was not taken into consideration when tolls are fixed. By so doing, the appellant regulates the respondent's revenues albeit in a seemingly indirect manner. I would therefore dismiss this argument.

(C) The Power to Revisit the Period During Which Interim Rates Were in Force

(i) Introduction

38 As indicated above, the appellant has examined the period during which interim rates were in force, i.e. from January 1, 1985 to October 14, 1986, for the purpose of ascertaining whether these interim rates were in fact just and reasonable. Following a factual finding that these rates were not just and reasonable, the one-time credit order now contested before this Court was made in order to remedy this situation. Thus, the effect of Decision 86-17 was not retroactive in nature since it does not seek to establish rates to replace or be substituted to those which were charged during that period. The one-time credit order is, however, retrospective in the sense that its purpose is to remedy the imposition of rates approved in the past and found in the final analysis to be excessive. Thus, the question before this Court is whether the appellant has jurisdiction to make orders for the purpose of remedying the inappropriateness of rates which were approved by it in a previous interim decision.

39 This question involves a determination of whether rates approved by interim order are inherently contingent as well as provisional or whether the statutory scheme established by the Railway Act and the National Transportation Act is so prospective in nature that it precludes such a retrospective review of interim rates approved by the appellant. Finally, it is also necessary to determine whether the appellant has jurisdiction to order the reimbursement of amounts which exceed the revenues [page1750] actually collected as a direct result of the interim rates.

(ii) The Distinction Between Interim and Final Orders

40 The respondent argues that the Railway Act and the National Transportation Act establish a regulatory regime which is exclusively prospective in nature because all rates, whether interim or final, must be just and reasonable. Thus, if interim rates have been approved on the basis that they are just and reasonable, no excessive revenues can be earned by charging such rates; interim rates, by reason only of their approval by the appellant, are presumed to be just and reasonable until they are modified by a subsequent order. According to the respondent, interim orders are therefore orders made "for the time being" until a more permanent order is made.

41 In his dissenting reasons, Hugessen J. points out quite accurately that if interim orders are simply orders made "for the time being", it will be impossible to distinguish final orders from interim orders within the statutory scheme established by the Railway Act and the National Transportation Act since all final orders may be revised by the appellant of its own motion and at any time: s. 335(1) of the Railway Act and s. 52 of the National Transportation Act. It is therefore impossible to say that final orders made under these statutes are final in the sense that they may never be reconsidered. The on-going nature of the appellant's regulatory activities necessarily entails a continuous review of past decisions concerning tolls and tariffs. Thus, all orders, whether final or interim, would be orders "for the time being" within the statutory scheme established by the Railway Act and the National Transportation Act.

42 Both the appellant and Hugessen J. rely heavily on Re Coseka Resources Ltd. and Saratoga Processing Co. (1981), 126 D.L.R. (3d) 705 (Alta. [page1751] C.A.) for the proposition that interim decisions must be distinguished from final decisions in that they may be reviewed in a retrospective manner. This distinction is based on the fact that interim decisions are made subject to "further direction" as prescribed by s. 60(2) of the National Transportation Act which, for convenience, I cite again:

> 60. ...
>
> (2) The Commission may, instead of making an order final in the first instance, make an interim order and reserve further directions either for an adjourned hearing of the matter or for further application. [Emphasis added.]

The statutory scheme analysed by the Alberta Court of Appeal in Re Coseka is substantially similar to though more clearly prospective than the statutory scheme established by the Railway Act and the National Transportation Act. Furthermore, s. 52(2) of the Public Utilities Board Act, R.S.A. 1970, c. 302, is identical in wording to s. 60(2) of the National Transportation Act. Laycraft J.A., as he then was, cited with approval by Hugessen J., wrote the following with respect to the possibility of revisiting the period during which interim rates were in force for the purpose of deciding whether those interim rates were in fact just and reasonable, at pp. 717-18:

> In my view, to say that an interim order may not be replaced by a final order is to attribute virtually no additional powers to the Board from s. 52 beyond those already contained in either the Gas Utilities Act or the Public Utilities Board Act to make final orders. The Board is by other provisions of the statute empowered by order to fix rates either on application or on its own motion. An interim order would be the same, and have the same effect, as a final order unless the "further direction" which the statute contemplates includes the power to change the interim order. On that construction of the section the interim order would be a "final" order in all but name. The Board would need no further legislative authority to issue a further "final" order since it may fix rates under s. 27 on its own motion without a further application. The provision for an interim order was intended to permit rates to be fixed subject to [page1752] correction to be made when the hearing is subsequently completed.
>
> It was urged during argument that s. 52(2) was merely intended to enable the Board to achieve "rough justice" during the period of its operation until a final order is issued. However, the Board is required to fix "just and reasonable rates" not "roughly just and reasonable rates". The words "reserve for further direction", in my view, contemplate changes as soon as the Board is able to determine those just and reasonable rates. [Emphasis added.]

43 I agree with Hugessen J. and with the reasons of Laycraft J.A. in Re Coseka where he made a careful review of previous cases. The statutory scheme established by the Railway Act and the National Transportation Act is such that one of the differences between interim and final orders must be that interim decisions may be reviewed and modified in a retrospective manner by a final decision. It is inherent in the nature of interim orders that their effect as well as any discrepancy between the interim order and the final order may be reviewed and remedied by the final order. I hasten to add that the words "further directions" do not have any magical, retrospective content. Under the Railway Act and the National Transportation Act, final orders are subject to "further [prospective] directions" as well. It is the interim nature of the order which makes it subject to further retrospective directions.

44 The importance of distinguishing final orders from interim orders is illustrated by the case of City of Calgary v. Madison Natural Gas Co. (1959), 19 D.L.R. (2d) 655 (Alta. C.A.). In Madison, the Public Utility Board (the "Board") was faced with an application by the City of Calgary for the reimbursement of amounts earned in excess of the rates of return allowed in orders 34 and 41 for the sale of natural gas. The Board had allowed a rate of return of 7 per cent but, due to its lack of useful information to predict the effect of rates on [page1753] the actual financial performance of the regulated entity, the rates per volume fixed by the Board actually yielded greater profits than anticipated. The Board refused to grant the demands made in the application because it felt it had no jurisdiction to revisit periods during which rates approved in a final decision were in force. This decision was confirmed by the Court of Appeal on the basis that, contrary to arguments made by the City of Calgary, orders 34 and 41 were final orders not governed by s. 35a(3) of the Natural Gas Utilities Act, which read as follows:

> 35a -- ...
>
> (3) The Board is hereby authorized, empowered and directed, on the final hearing, to give consideration to the effect of the operation of such interim or temporary order and in the final order to make, allow or provide for such adjustments, allowances or other factors, as to the Board may seem just and reasonable.

Order 34 provided that the price was set at 9 cents per mcf and that "if it should turn out that there is a surplus, it can be dealt with when the time arrives" which led to the argument that this order was in fact an interim order. Johnson J.A. dismissed this argument in the following terms, at pp. 662-63:

> It is the submission of the appellants that O. 34 and O. 41 are interim or temporary orders and the Board can now deal with these surpluses in accordance with s-s (3). As I have mentioned, orders fixing interim prices were made while the Board was hearing the application and considering its report. These, of course, were superseded by the order now under consideration. Orders 34 and 41 are, of course, not final orders in the sense that judgments are final. The Act contemplates that subsequent applications will be made to change the price fixed by these orders. They are nonetheless final so far as each application is concerned.

It is useful to note that the respondent relies heavily on the Madison case for the proposition that a regulated entity cannot be forced to disgorge [page1754] profits legally earned by charging rates approved by the relevant regulatory authority on the basis that they are just and reasonable. Since the City of Calgary sought to obtain the reimbursement of profits earned by charging rates approved by final order, this case does not support the respondent's position.

45 A consideration of the nature of interim orders and the circumstances under which they are granted further explains and justifies their being, unlike final decisions, subject to retrospective review and remedial orders. The appellant may make a wide variety of interim orders dealing with hearings, notices and, in general, all matters concerning the administration of proceedings before the appellant. Such orders are obviously interim in nature. However, this is less obvious when an interim order deals with a matter which is to be dealt with in the final decision, as was the case with the interim rate increase ordered in Decision 84-28. If interim rate increases are awarded on the basis of the same criteria as those applied in the final decision, the interim decision would serve as a preliminary decision on the merits as far as the rate increase is concerned. This, however, is not the purpose of interim rate orders.

46 Traditionally, such interim rate orders dealing in an interlocutory manner with issues which remain to be decided in a final decision are granted for the purpose of relieving the applicant from the deleterious effects caused by the length of the proceedings. Such decisions are made in an expeditious manner on the basis of evidence which would often be insufficient for the purposes of the final decision. The fact that an order does not make any decision on the merits of an issue to be settled in a final decision and the fact that its purpose is to provide temporary relief against the deleterious effects of the duration of the proceedings are essential characteristics of an interim rate order.

47 In Decision 84-28, the appellant granted the respondent an interim rate increase on the basis of [page1755] the following criteria which, for convenience, I cite again (at p. 9):

> The Commission considers that, as a rule, general rate increases should only be granted following the full public process contemplated by Part III of its Telecommunications Rules of Procedure. In the absence of such a process, general rate increases should not in the Commission's view be granted, even on an interim basis, except where special circumstances can be demonstrated. Such circumstances would include lengthy delays in dealing with an application that could result in a serious deterioration in the financial condition of [page1756] an applicant absent a general interim increase.

Decision 84-28 was truly an interim decision since it did not seek to decide in a preliminary manner an issue which would be dealt with in the final decision. Instead, the appellant granted the interim rate increase on the basis that such an increase was necessary in order to prevent the respondent from having serious financial difficulties.

48 Furthermore, the appellant consistently reiterated throughout the procedures which led to Decision 86-17 its intention to review the rates charged for the test year 1985 and up to the date of the final decision. Holding that the interim rates in force during that period cannot be reviewed would not only be contrary to the nature of interim orders, it would also frustrate and subvert the appellant's order approving interim rates.

49 It is true, as the respondent argues, that all telephone rates approved by the appellant must be just and reasonable whether these rates are approved by interim or final order; no other conclusion can be derived from s. 340(1) of the Railway Act. However, interim rates must be just and reasonable on the basis of the evidence filed by the applicant at the hearing or otherwise available for the interim decision. It would be useless to order a final hearing if the appellant was bound by the evidence filed at the interim hearing. Furthermore, the interim rate increase was granted on the basis that the length of the proceedings could cause a serious deterioration in the financial condition of the respondent. Only once such an emergency situation was found to exist did the appellant ask itself what rate increase would be just and reasonable on the basis of the available evidence and for the purpose of preventing such a financial deterioration. The inherent differences between a decision made on an interim basis and a decision made on a final basis clearly justify the power to revisit the period during which interim rates were in force.

50 The respondent argues that the power to revisit the period during which interim rates were in force cannot exist within the statutory scheme established by the Railway Act and the National Transportation Act because these statutes do not grant such a power explicitly, unlike s. 64 of the National Energy Board Act, R.S.C., 1985, c. N-7. The powers of any administrative tribunal must of course be stated in its enabling statute but they may also exist by necessary implication from the wording of the act, its structure and its purpose. Although courts must refrain from unduly broadening the powers of such regulatory authorities through judicial law-making, they must also avoid sterilizing these powers through overly technical interpretations of enabling statutes. I have found that, within the statutory scheme established by the Railway Act and the National Transportation Act, the power to make interim orders necessarily implies the power to revisit the period during which interim rates were in force. The fact that this power is provided explicitly in other statutes cannot modify this conclusion based as it is on the interpretation of these two statutes as a whole.

51 I am bolstered in my opinion by the fact that the regulatory scheme established by the Railway Act and the National Transportation Act gives the appellant very broad procedural powers for the purpose of ensuring that telephone rates and tariffs are, at all times, just and reasonable. Within this regulatory framework, the power to make appropriate orders for the purpose of [page1757] remedying interim rates which are not just and reasonable is a necessary adjunct to the power to make interim orders.

52 It is interesting to note that, in the context of statutory schemes which did not provide any power to set interim rates, the United States Supreme Court has held that regulatory agencies have both the power to impose interim rates and the power to make reimbursement orders where the interim rates are found to be excessive in the final order: United States v. Fulton, 475 U.S. 657 (1986), at pp. 669-71; Trans Alaska Pipeline Rate Cases, 436 U.S. 631 (1978), where Brennan J. wrote the following comments at pp. 654-56:

> Finally, petitioners contend that the Commission has no power to subject them to an obligation to account for and refund amounts collected under the interim rates in effect during the suspension period and the initial rates which would become effective at the end of such a period.... In response, we note first that we have already recognized in Chessie that the Commission does have powers "ancillary" to its suspension power which do not depend on an express statutory grant of authority. We had no occasion in Chessie to consider what the full range of such powers might be, but we did indicate that the touchstone of ancillary power was a "direc(t) relat(ionship)" between the power asserted and the Commission's "mandate to assess the reasonableness of ... rates and to suspend them pending investigation if there is a question as to their legality." 426 U.S., at 514.
>
> . . .
>
> Thus, here as in Chessie, the Commission's refund conditions are a "legitimate, reasonable, and direct adjunct to the Commission's explicit statutory power to suspend rates pending investigation," in that they allow the Commission, in exercising its suspension power, to pursue "a more measured course" and to "offe(r) an alternative tailored far more precisely to the particular circumstances" of these cases. Since, again as in Chessie, the measured course adopted here is necessary to strike a proper balance between the interests of carriers and the public, we think the Interstate Commerce Act should be construed to confer on the Commission the [page1758] authority to enter on this course unless language in the Act plainly requires a contrary result.

This approach to the interpretation of statutes conferring regulatory authority over rates and tariffs is only the expression of the wider rule that the court must not stifle the legislator's intention by reason only of the fact that a power has not been explicitly provided for.

53 The appellant has also argued that the power to "vary" a previous decision, whether interim or final, found in s. 66 of the National Transportation Act, includes the power to vary these decisions in a retroactive manner. Given my conclusion based on the inherent nature of interim orders, it is unnecessary for me to deal with this argument.

(iii) The Relevance of the Distinction Between Positive Approval and Negative Disallowance Schemes of Rate Regulation

54 Much was said in argument about the difference between positive approval schemes and negative disallowance schemes with respect to the power to act retrospectively. The first category includes schemes which provide that the administrative agency is the only body having statutory authority to approve or fix tolls payable to utility companies; these schemes generally stipulate that tolls shall be "just and reasonable" and that the administrative agency has the power to review these tolls on a proprio motu basis or upon application by an interested party. The second category includes schemes which grant utility companies the right to fix tolls as they wish but also grant users the right to complain before an administrative agency which has the power to vary those tolls if it finds that they are not "just and reasonable". It has generally been found that negative disallowance schemes provide the power to make orders which are retroactive to the date of the application by the ratepayer who claims that the rates are not "just and reasonable". On the other hand, positive approval schemes have been found to be exclusively prospective in nature and not to allow orders [page1759] applicable to periods prior to the final decision itself. A full discussion of this issue was made by Estey J. in Nova v. Amoco Canada Petroleum Co., [1981] 2 S.C.R. 437, at pp. 450-51, and I do not propose to repeat or to criticize what was said in that case with respect to the power to review rates approved by a previous final order. I am of the opinion that the regulatory scheme established by the Railway Act and the National Transportation Act is a positive approval scheme inasmuch as the respondent's rates are subject to approval by the appellant. However, the Nova case only dealt with the power to review rates approved in a previous final decision and, as I have said before, entirely different considerations apply when interim rates are reviewed.

55 It has often been said that the power to review its own previous final decision on the fairness and the reasonableness of rates would threaten the stability of the regulated entity's financial situation. In Regina v. Board of Commissioners of Public Utilities (1966), 60 D.L.R. (2d) 703, Ritchie J.A., wrote the following comments on this issue, at p. 729:

> The distributor contends that in the absence of any express limitation or restriction or an express provision as to the effective date of any order made by the board, the jurisdiction conferred on the board by the Legislature includes jurisdiction to make orders with retrospective effect. Reliance is placed on Bakery and Confectionery Workers International Union of America, Local 468 v. Salmi, White Lunch Ltd. v. Labour Relations Board of British Columbia, 56 D.L.R. (2d) 193, [1966] S.C.R. 282, 55 W.W.R. 129 which it is contended must be applied when interpreting s. 6(1) of the Act.
>
> The clear object of the Act is to ensure stability in the operation of public utilities and the maintenance of just, reasonable and non-discriminatory rates. That object would be defeated if the board having, on November 14, 1962, made an order fixing the rates to be paid by the distributor for natural gas purchased from the producer, reduced those rates on February 19, 1966, more than three years later, and directed the reduced rates be [page1760] effective as from January 1, 1962, or as from any other date prior to February 19, 1966.

and further at p. 732:

> In no section of the Act do I find any wording indicating an intention on the part of the Legislature to confer on the board authority to make orders fixing rates with retrospective effect or any language requiring a construction that such authority has been bestowed on the board. To so interpret s. 6(1) would render insecure the position of not only every public utility carrying on business in the Province but also the position of every customer of such public utility.

However, Ritchie J.A.'s comments deal with the Public Utilities Act, R.S.N.B. 1952, c. 186, which did not provide the Board with any power to make interim orders. I readily agree that Ritchie J.A.'s concerns about the financial stability of utility companies are valid when one is faced with the argument that a Board has the power to revisit its own previous final decisions. Since no time limit could be placed on the period which could be revisited, any power to revisit previous final decisions would have to be explicitly provided in the enabling statute. Furthermore, even if final orders are "for the time being", it does not necessarily follow that they must be stripped of all their finality through the judicial recognition of a power to revisit a period during which final rates were in force.

56 However, there should be no concern over the financial stability of regulated utility companies where one deals with the power to revisit interim rates. The very purpose of interim rates is to allay the prospect of financial instability which can be caused by the duration of proceedings before a regulatory tribunal. In fact, in this case, the respondent asked for and was granted interim rate increases on the basis of serious apprehended financial difficulties. The added flexibility provided by the power to make interim orders is meant to foster financial stability throughout the regulatory process. The power to revisit the period during which interim rates were in force is a necessary corollary of this power without which interim orders made in emergency situations may [page1761] cause irreparable harm and subvert the fundamental purpose of ensuring that rates are just and reasonable.

57 Even though Parliament has decided to adopt a positive approval regulatory scheme for the regulation of telephone rates, the added flexibility provided by the power to make interim orders indicates that the appellant is empowered to make orders as of the date at which the initial application was made or as of the date the appellant initiated the proceedings of its own motion. The underlying theory behind the rule that a positive approval scheme only gives jurisdiction to make prospective orders is that the rates are presumed to be just and reasonable until they are modified because they have been approved by the regulatory authority on the basis that they were indeed just and reasonable. However, the power to make interim orders necessarily implies the power to modify in its entirety the rate structure previously established by final order. As a result, it cannot be said that the rate review process begins at the date of the final hearing; instead, the rate review begins when the appellant sets interim rates pending a final decision on the merits. As was stated in obiter in Re Eurocan Pulp & Paper Co. and British Columbia Energy Commission (1978), 87 D.L.R. (3d) 727 (B.C.C.A.), with respect to a similar though not identical legislative scheme, the power to make interim orders effectively implies the power to make orders effective from the date of the beginning of the proceedings. In turn, this power must comprise the power to make appropriate orders for the purpose of remedying any discrepancy between the rate of return yielded by the interim rates and the rate of return allowed in the final decision for the period during which they are in effect so as to achieve just and reasonable rates throughout that period.

[page1762]

(iv) The Power to Make a One-time Credit Order

58 Once it is decided, as I have, that the appellant does have the power to revisit the period during which interim rates were in force for the purpose of ascertaining whether they were just and reasonable, it would be absurd to hold that it has no power to make a remedial order where, in fact, these rates were not just and reasonable. I also agree with Hugessen J. that s. 340(5) of the Railway Act provides a sufficient statutory basis for the power to make remedial orders including an order to give a one-time credit to certain classes of customers.

59 CNCP Telecommunications argues that the one-time credit order should be limited to the amount of revenues actually derived as a direct result of the 2 per cent interim rate increase and that these excess revenues should be refunded to the actual customers who paid them. The presumption behind this argument is that the portion of the interim rates corresponding to the final rates in force prior to the beginning of the proceedings cannot be held to be unjust or unreasonable until a final decision is rendered. As I have held that the appellant has jurisdiction to review the fairness and the reasonableness of these interim rates in their entirety because the rate-review process starts as of the date of the beginning of the proceedings, this argument must be dismissed.

60 Finally, it is true that the one-time credit ordered by the appellant will not necessarily benefit the customers who were actually billed excessive rates. However, once it is found that the appellant does have the power to make a remedial order, the nature and extent of this order remain within its jurisdiction in the absence of any specific statutory provision on this issue. The appellant admits that the use of a one-time credit is not the perfect way of reimbursing excess revenues. However, in view of the cost and the complexity of finding who actually paid excessive rates, where these persons reside and of quantifying the amount of excessive payments made by each, and having regard to the appellant's broad jurisdiction in [page1763] weighing the many factors involved in apportioning respondent's revenue requirement amongst its several classes of customers to determine just and reasonable rates, the appellant's decision was eminently reasonable and I agree with Hugessen J. that it should not be overturned.

VI - Conclusion

61 In my opinion, the appellant had jurisdiction to review the interim rates in force prior to Decision 86-17 for the purpose of ascertaining whether they were just and reasonable, had jurisdiction to order the respondent to grant the one-time credit described in Decision 86-17 and has committed no error in so doing.

62 I would allow the appeal and confirm the appellant's decision, with costs in all courts.

3

Ontario Energy Board

Commission de l'Énergie de l'Ontario

Ontario

RP-2001-0033 1

EB-2003-0268

IN THE MATTER OF the *Ontario Energy Board Act*, S.O. 1998, c. 15, Schedule B; 2

AND IN THE MATTER OF an Application by Sithe Energies Canadian Development, Ltd. for an order or orders granting leave to construct an electricity transmission line, make an interconnection with the transmission system owned by Hydro One Networks Inc., and construct a transmission line over a highway and other utility lines, all in the City of Brampton; 3

AND IN THE MATTER OF a Notice of Proposal pursuant to section 81 of the *Ontario Energy Board Act*, 1998 by Sithe Energies Canadian Development, Ltd., a generator, to construct a transmission system; 4

AND IN THE MATTER OF a Motion by Sithe Energies Canadian Development, Ltd. to vary the Order issued by the Ontario Energy Board dated September 9, 2002 in respect of the Applicant to whom the Order applied, and the termination date of the Order. 5

BEFORE: 6

Arthur Birchenough 7
Presiding Member

George A. Dominy 8
Member

DECISION AND ORDER 9

Sithe Energies Canadian Development, Ltd. (the "Applicant") filed a motion dated October 16, 10
2003 with the Ontario Energy Board to vary an order of the Board issued to Sithe Energies Cana-

dian Development, Ltd. on September 9, 2002 (amended by a vary order dated November 20, 2002). The variance sought is :

1. to change the party to whom the order was issued (namely Sithe Energies Canadian Development, Ltd.), to Sithe Canada Ltd.; and 11

2. to change the conditions of approval contained in Appendix A to the order to provide that the termination date for the order be extended to June 30, 2005. 12

Sithe Energies Canadian Development, Ltd.'s Motion also requested orders of the Board: 13

3. waiving the requirement contained in rule 42.03 requiring that the Notice of Motion be filed and served within 20 calendar days of the date of the Previous Order; 14

4. dispensing with an oral hearing of the Notice of Motion; and 15

5. such further and other orders as the Board considers just and necessary. 16

The Board assigned Board File No. RP-2001-0033/EB-2003-0268 to this Motion. 17

As part of a set of tax planning transactions involving the parent company of both Sithe Energies 18
Canadian Development, Ltd. and Sithe Canada Ltd., it is proposed that the shares of Sithe Energies Canadian Development, Ltd. be conveyed to Sithe Canada Ltd., whereupon Sithe Energies Canadian Development, Ltd. would be wound up and cease to exist. The transactions are scheduled to close on November 1, 2003. The Motion requesting that the previous order be varied to give authority for leave to construct to Sithe Canada Ltd. has therefore been made.

The order granted to Sithe Energies Canadian Development, Ltd., leave to construct a double circuit 19
electricity transmission line approximately 2 km in length from the proposed Goreway generating station, and to make an interconnection at Tower 26 with the electricity transmission lines owned by Hydro One Networks Inc., ("Hydro One"), all in the City of Brampton. The original order, in condition 1.2 of the order, stated that the authorization for leave to construct would terminate on December 31, 2003 unless construction had commenced by that date. The variance sought would extend the termination date to June 30, 2005. The applicant explained that the changes to electricity legislation had delayed decisions to proceed with construction of the Goreway generating station and associated transmission facilities. However, the Applicant's family of companies and its successor remain active in the Ontario electricity market, and have submitted a proposal to the Independent Market Operator ("IMO") to provide 1009 Megawatts of power. An extension to the termination date of the leave to construct order was therefore sought.

Sithe confirmed that Notice of Motion was delivered to all intervenors in the original application. 20
Hydro One, Ontario Realty Corporation, Ontario Power Generation Inc. and Toronto Hydro-Electric System Limited had no objection to extension of the leave to construct termination date. IMO

supported the extension but submitted that an additional clause be added to the Conditions of Approval requiring that the Applicant file periodic project status reports for the duration of the order. Enbridge Gas Distribution Inc. had concerns requiring that the new owner advise it on decisions affecting the construction, operation and ownership of an associated gas pipeline.

21

The Board notes that over a year has passed since the original order was issued. *The Statutory Powers Procedure Act*, R.S.O. 1990 c. S-22, section 21.2 (2) requires that a tribunal's review of its own decision takes place within "a reasonable time" after the decision or order is made. The Applicant has asked that the Board consider this motion to vary despite the significant lapse of time since the original order was made. What is a "reasonable time" will vary with the circumstances of each case. In this matter, the Board accepts the explanation of the Applicant for the delay in construction and the consequent request for a variance. In the unusual circumstances of this case, the Board waives the requirement in its Rules of Practice and Procedure that motions to vary must be made within twenty days of the original order and will consider the motion for variance.

22

The first change sought is akin to an application under section 18 of the *Ontario Energy Board Act*, which states that no authority given by the Board shall be transferred or assigned without leave of the Board. In this case, the need for the transfer of authority is driven by a corporate reorganization, undertaken for tax planning purposes. As there is no real change of control involved in the transaction, the Board finds that there are no safety or public interest concerns raised by the proposed variance. Further, there is nothing on the record to suggest that the proposed transfer should adversely affect the development and maintenance of a competitive market. The Board finds that granting the first change sought in the Motion is in the public interest.

23

The second variance sought is the extension of time before expiry of the authorization for leave to construct. If this variance is not granted, then Sithe Canada Ltd. will need to re-apply for leave to construct on the same project for which leave has already been granted. As the Board understands it, there has been no significant change to the leave to construct proposal since the issuance of the original order. No parties to that proceeding, who were served with this Motion, have raised objections to the extension of time to begin the project, other than requiring conditions whereby periodic status reports on the project are filed or when decisions affecting an associated gas pipeline are made. The Board finds that to vary the order to grant the extension sought by Sithe Energies Canadian Development, Ltd. is in the public interest with conditions requiring periodic status reporting during the duration of the order.

24

THE BOARD ORDERS THAT:

25

The order of the Board RP-2001-0033 issued to Sithe Energies Canadian Development, Ltd. on September 9, 2002 (amended by vary order dated November 20, 2002) is varied as follows :

26

1. The authorizations at pages three and four, numbered paragraphs 1 through 3, granted to Sithe Energies Canadian Development, Ltd. are hereby transferred to Sithe Canada Ltd. References to Sithe Energies Canadian Development, Ltd in the Conditions of Approval, in Appendix A of the original order, are revised to read "Sithe Canada Ltd."

2. The date of December 31, 2003, appearing in paragraph 1.2 of Appendix A (the Conditions of Approval) to the order is replaced with the date of June 30, 2005 and with conditions requiring reporting on project status for the duration of this order. 27

3. The revised Conditions of Approval are attached as Appendix A [12YYK-0:1]to this order. 28

ISSUED at Toronto, October 31, 2003 29

ONTARIO ENERGY BOARD 30

Peter H. O’Dell
Assistant Secretary

4

In the Court of Appeal of Alberta

Citation: Calgary (City) v. Alberta (Energy and Utilities Board), 2010 ABCA 132

Date: 20100423
Docket: 0801-0030-AC
Registry: Calgary

Between:

City of Calgary

Appellant
(Applicant)

- and -

Alberta Energy and Utilities Board

Respondent
(Respondent)

- and -

ATCO Gas and Pipelines Ltd.

Respondent
(Respondent)

The Court:

The Honourable Mr. Justice Jean Côté
The Honourable Madam Justice Constance Hunt
The Honourable Madam Justice Marina Paperny

Reasons for Judgment Reserved of The Honourable Madam Justice Hunt
Concurred in by The Honourable Madam Justice Paperny

Reasons for Judgment Reserved of The Honourable Mr. Justice Côté
Concurring in Part

Appeal from the Alberta Energy and Utilities Board
Decision 2008-001 dated January 8, 2008 and
Decision 2005-036 dated April 28, 2005

Reasons for Judgment Reserved of
The Honourable Madam Justice Hunt

[1] I agree with Côté J.A. that the orders under appeal should be vacated, but reach that conclusion for different reasons. I would allow the appeal and return the matter to the Alberta Utilities Commission ("Board[1]") for reconsideration in accordance with this judgment.

Facts

History of Deferred Gas Accounts (DGA)

[2] The modern origin of deferred gas accounts (formerly deferred gas accounting) ("DGA") is a 1988 decision which arose out of a utility's general rate application: *Re Northwestern Utilities Limited*, In the matter of an application to determine rate base and fix a fair return thereon for the test years 1987 and 1988, Decision E88018, (Public Utilities Board). The use of a DGA was proposed to deal with seasonal price differences in gas costs. It required segregating the sales rate into two components, gas and non-gas. The latter would be determined in a general rate application while the former, the Gas Cost Recovery Rate ("GCRR"), would be determined twice a year using a formal filing process, subject to Board monitoring or review by way of a hearing. Adjustments to actual and estimated costs of gas would be held in the DGA then reconciled for refund to or recovery from consumers.

[3] In approving these procedures, the Board emphasized that the outcome would be "customers pay for no more or less than the price of gas actually incurred ... the shareholders would not gain or be penalized as a result of price variations ...": p. 325. The use of a DGA would be beneficial to customers: p. 326. The Board described the GCRR's gas cost component as "interim": p. 327. This early decision demonstrates that the Board intended to scrutinize the use of the DGA on an ongoing basis.

[4] The principles from this decision were applied the same year to Canadian Western Natural Gas Company Limited, the respondent ATCO's predecessor: *Re Canadian Western Natural Gas Company Limited*, In the matter of an Application by Canadian Western Natural Gas Company Limited for approval of Deferred Gas Accounting and Reconciliation procedures respecting its gas supply costs, Order E88019, (Public Utilities Board, 1988). The DGAs at issue here were then created.

[5] In 2001 ATCO and the appellant City of Calgary (Calgary) were both parties to a hearing that considered, *inter alia*, the methodology for determining the GCRR: Methodology for Managing

[1] "Board" means the regulator of Alberta's gas industry which has, over time, been the Public Utilities Board, the Energy and Utilities Board and the Alberta Utilities Commission.

Gas Supply Portfolios and Determining Gas Cost Recovery Rates (Methodology) Proceeding and Gas Rate Unbundling (Unbundling) Proceeding, Part A: GCRR Methodology and Gas Rate Unbundling. Decision 2001-75 (Alberta Energy and Utilities Board, 2001). Its context was the transition to competitive retail gas service. The Board noted its general supervisory power over utilities and its power to fix just and reasonable rates as the basis of its authority to deal with the issues in the hearing: p. 10.

[6] The Board described "GCRR/DGA Programs" as follows at p. 56:

> The effect of a Gas Cost Recovery Rate/Deferred Gas Account (GCRR/DGA) mechanism is to spread the cost of gas acquisition and management over a forecast period, keeping consumer gas prices stable during that period. <u>The use of a DGA to keep track of differences between actual and forecast gas costs ensures that customers pay no more and no less than actual costs incurred on their behalf</u>. However, the reconciliation between forecast and actual costs occurs over one or more seasons. [footnote omitted] During periods of rapid gas price increase, as experienced in the winter of 2000/2001, the accumulated balances in the DGA can become large. The current system of GCRRs/DGAs has defined tolerance limits on the size of the DGAs, requiring the utilities to file for gas rate adjustments when the variance between forecast and actual costs becomes too large. [emphasis added]

[7] The Board determined that utilities no longer needed to "file formal GCRR applications with the Board, but would instead file ... on a monthly basis", and monthly adjustments would be made to the GCRR: p. 64. Interested parties would have an opportunity to raise concerns about the monthly GCRRs filed by the utilities. Reconciliation of DGA balances would be done on a three-month rolling basis. The Board set a date for the commencement of this system, "in conjunction with the revised interim rates noted elsewhere in this Decision": p. 64.

[8] Since then, the use of DGAs has evolved. For example, in ATCO Gas South Jumping Pound Meter Station – Gas Measurement Adjustment Application No. 1314487, Decision 2004-013, the Board approved adjustments to an ATCO DGA balance to reflect measurement errors caused by equipment malfunction. Part of the Board's rationale was that the adjustment was made in accordance with approved DGA procedures. A related adjustment to the DGA (timing costs) was rejected by the Board because it was not a previously approved DGA adjustment.

[9] In other DGA decisions, the Board considered factors such as the amount of the adjustment, the timeliness of the application, whether the utility had acted responsibly, the foreseeability of the problem, and whether consumers who received the service were bearing the cost of the adjustment, see e.g., Northwestern Utilities Limited, 1996/1997 Winter Period Gas Cost Recovery Rate, Decision U97053 97053; IN THE MATTER of a Gas Cost Recovery Rate Refund for the 2001 Summer Period for AltaGas Utilities Inc. Order U2001-316.

Origin of this Dispute

[10] In May 2004, ATCO sought Board approval to correct balances in the DGAs for each of its south and north gas distribution service territories. The proposed adjustment to the DGA for northern Alberta was largely attributable to *overstated* gas costs from January 1998 to February 2004, whereas in southern Alberta the actual gas costs ATCO incurred from January 1999 to February 2004 were *understated*. ATCO proposed that its present southern Alberta consumers would pay the shortfalls and that it would refund excesses to its present northern Alberta consumers. Since this appeal concerns only the adjustment proposed to the southern DGA, I make no further reference to the northern DGA.

[11] The adjustments were sought because there had been inaccurate reporting of gas being transported for other entities through ATCO's pipeline network ("transportation imbalances"). It appears the errors began when the administration of ATCO's gas transportation system was moved to a new system, the transportation information system ("System").

[12] ATCO had included the transportation imbalances as prior period adjustments in the DGA as part of its December 2003 GCRR filings. While producing supplementary information requested by the Board, ATCO detected additional transportation imbalances. It then refiled its December 2003 GCRR *excluding* the transportation imbalance adjustments. ATCO engaged chartered accountants to review its re-calculation of the imbalances. The Board's treatment of ATCO's subsequent application to record the revised transportation imbalances in the DGA is at the root of this appeal.

Board Decisions

[13] Three Board decisions are relevant. Each is described in more detail beginning at para. 16.

[14] The first decision partly allowed ATCO's application to use the DGA/GCRR reconciliation process to record the transportation imbalances: ATCO Gas, A Division of ATCO Gas and Pipelines Ltd. Imbalance and Production Adjustments – Deferred Gas Account Application No. 1347852, Decision 2005-036, ("DGA Decision"). In the second, the Board established a general rule that the DGA/GCRR reconciliation process has a two-year limitation period: ATCO Gas, A Division of ATCO Gas and Pipelines Ltd., Deferred Gas Account Limitation Period, Decision 2006-042 ("Limitations Decision"). The third focused on the Board's jurisdiction to make the DGA and the Limitations Decisions: ATCO Gas, A Division of ATCO Gas and Pipelines Ltd. Reconsideration of Decision 2005-036 Deferred Gas Account, Imbalance and Production Adjustments, Application No. 1524763 Proceeding ID. 5, Decision 2008-001 ("DGA Reconsideration Decision).

[15] As to the DGA and DGA Reconsideration Decisions, Calgary obtained leave to appeal on the following question: "Whether the Board erred in law or in jurisdiction by allowing for the recovery, in 2005, of costs or expenses that were incurred between 199[9][2] and 2004.": *Calgary (City) v. Alberta (Energy and Utilities Board*), 2009 ABCA 150 at para. 9, [2009] A.J. No. 408. ATCO has discontinued its application for leave to appeal the Limitations Decision.

DGA Decision (Decision 2005-036)

[16] The Board defined the central issue as "whether or not it is appropriate for the DGA to be a vehicle of all and any updates and corrections other than for price and actual gas sales (or deliveries)": p. 10.

[17] In reviewing the history of the DGA/GCRR process, the Board noted that the DGA/GCRR process was originally approved to provide a method for adjusting for gas price volatility and that, by April 2002, the process was refined so that monthly (not seasonal) reconciliations were made: p. 10. Over time, DGAs were used without complaint to adjust gas rates for reasons unrelated to price volatility, including measurement corrections. While it had become a "relatively common occurrence" for DGAs to be used for making prior period adjustments, most were made "within a reasonable time period": *Id*.

[18] The Board was troubled by the evolution of DGAs into a 'catch all' method for fixing all possible gas cost errors and by the timing of the adjustments. It criticized ATCO for the design errors in the System report and its delay in detecting them, reinforcing its expectation that ATCO's internal controls should detect material errors in a timely way.

[19] Notwithstanding these misgivings, the Board permitted ATCO to recover eighty-five percent of the amounts it sought through adjustments to its DGA.

Limitations Decision (Decision 2006-042)

[20] The Board's concerns about ATCO's delay in applying for the imbalance adjustments led to a hearing to examine whether it ought to impose a general policy limiting the extent to which adjustments are made to DGAs.

[21] In the resulting Limitations Decision, the Board considered its jurisdiction to establish limitation periods for the DGA/GCRR process in the context of its statutory mandate to set just and

---

[2] Calgary did not challenge the adjustments the Board approved to ATCO's northern territory DGA arising from transportation imbalances for the 1998 - 2004 period (Board factum at para. 14). Accordingly, 1999 (not 1998, as was stated in the leave decision) is the appropriate starting point.

reasonable rates and court decisions approving their use. It concluded that setting the GCRR requires the use of DGAs. Moreover:

> <u>the deferral nature of the DGAs is specifically contemplated and acknowledged when the rates are set</u>. Deferral accounts, by their nature, anticipate adjustments such as the ones at issue in this matter and, as such, cannot be said to constitute retroactive rate-making. The Supreme Court of Canada has approved the use of deferral accounts for gas and has further noted that such a mechanism is a purely administrative matter [citation omitted]. In *EPCOR Generation Inc. v. AEUB*, 2003 ABCA 374, the Alberta Court of Appeal adopted the same approach and stated that as the deferral account in issue in that decision was not closed, it was not a final order, and was not retroactive rate making or procedurally unfair.
>
> Consequently, the Board considers that a DGA has not been subject to any limitation regarding jurisdiction either by way of legislation, past Board decision or court ruling which would have prevented the Board from considering prior period adjustments to a DGA. In fact the Board has dealt with prior period adjustments to DGAs since their inception in 1987, with the prior periods being of varying lengths.

p. 4 (emphasis added).

[22] The Board adopted a general limitation period of two years prior to the effective date of the proposed GCRR for refunds to and recoveries from consumers. It permitted applications for

> approval of an adjustment to the DGA, where the cause of the adjustment originates outside the two-year limitation period, provided the following conditions are met:
>
> > (a) the adjustment sought exceeds the threshold value by being greater than 5% of the average monthly DGA gas commodity costs of the previous 12 months; and
> >
> > (b) the adjustment arose from special circumstances that were not within the utility's control.

p. 17

[23] As regards possible 'inter-generational equity' issues (a concept discussed more fully at para. 48 that means utility consumers should pay the costs associated with *their* consumption of the service, and future consumers should not benefit from or be burdened by the cost of services consumed by past consumers), the Board said at p. 12:

> While intergenerational equity questions ... arise ... particularly in relation to deferral accounts, the Board believes in this case that the imposition of a limitation period for DGAs assists in addressing the intergenerational issue raised ... because it limits the adjustments in the ordinary course. [ATCO] is correct in pointing out that <u>deferred accounts have an inherent intergenerational aspect</u>; <u>however, the Board considers that it is important to not allow too long a period before dealing with adjustments</u>. [emphasis added]

<u>*DGA Reconsideration Decision (Decision 2008-001)*</u>

[24] Calgary was granted leave to appeal the DGA Decision on the question of whether the Board was authorized under its governing legislation to approve any of the adjustments to the Deferred Gas Account applied for by ATCO Gas. Following a hearing, this Court concluded that since the issue of the Board's jurisdiction to grant ATCO's May 2004 application had not been raised before the Board, the evidentiary record necessary for an appeal was lacking: *Calgary (City of) v. ATCO Gas and Pipelines Ltd.*, 2007 ABCA 133, 404 A.R. 317. The Court returned the matter to the Board, which then considered whether it was "authorized under its governing legislation to approve adjustments to the ATCO Gas DGA in 2005 for costs and expenses incurred between 199[9] and 2004": p. 2.

[25] Calgary argued that the Board's jurisdiction was limited by section 40 of the *Gas Utilities Act* (see para. 27) such that "the Board's jurisdiction to consider prior period financial activity of a utility is limited to a 12-month period, even when the financial activity occurs in a deferral account approved by the Board": p. 7. The Board disagreed, partly because of its interpretation of its broad statutory mandate to fix just and reasonable rates. The Board reasoned that DGAs would serve no purpose under Calgary's interpretation because section 40 specifically authorizes the Board to take into account excess revenues or losses in "the whole of the fiscal year" of the rate application (ss. 40(a)(i)) and in any consecutive two-year period thereto (ss. 40(a)(iii)).

[26] The Board reiterated its Limitations Decision's conclusion on jurisdiction, found above at para. 21.

<u>Legislation</u>

[27] When ATCO applied for this DGA adjustment in 2004, the relevant legislation provided (with emphasis):

***Alberta Energy and Utilities Board Act*, R.S.A. 2000. c. A-17**

Powers of the Board

15(1) For the purposes of carrying out its functions, the Board has all the powers, rights and privileges of the ... PUB that are granted or provided for by any enactment or by law.

[...]

(3) Without restricting subsection (1), the Board may do all or any of the following:

(a) make any order that the ... PUB may make under any enactment;
[...]
(d) with respect to an order made by the Board ... in respect of matters referred to in clauses (a) to (c), make any further order and impose any additional conditions that the Board considers necessary in the public interest;
(e) make an order granting the whole or part only of the relief applied for;

[...]

26(1) Subject to subsection (2), an appeal lies from the Board to the Court of Appeal on a question of jurisdiction or on a question of law.

***Gas Utilities Act*, R.S.A. 2000, c. G-5**

The word "Board" is defined as the Public Utilities Board in section 1(b).

Powers of Board

36 The Board ... may ...

(a) fix just and reasonable ... rates, ...
[...]
(e) require an owner of a gas utility to supply and deliver gas to the persons, for the purposes, at the rates, prices and charges and on the terms and conditions that the Board directs....

Rate base

37(1) In fixing just and reasonable rates ... the Board shall determine a rate base for the property of the owner of the gas utility used or required to be used to provide service to the public within Alberta and on determining a rate base it shall fix a fair return on the rate base. ...

Schedule of rates

38(1) For the purpose of fixing the just and reasonable rates that may be charged to consumers of gas by an owner of a gas utility who purchases gas pursuant to a contract under which provision is made

(a) for the progressive increase in the price of gas to the owner of the gas utility,
(b) for an increase in the price of gas to the owner of the gas utility by reason of changes in any prices received by the owner on resale of the gas,
(c) for an increase in the price of gas to the owner of the gas utility by reason of the payment of higher prices by any purchaser of gas in any gas producing area, or
(d) for the redetermination of the price of gas to the owner of the gas utility either by agreement of the parties or pursuant to arbitration,

the Board ... may receive for filing a new schedule of rates that are alleged by the owner to be occasioned by the rise in the price required to be paid by the owner for purchased gas.

(2) The new schedule may be put into effect by the owner of the gas utility on receiving the approval of the Board to it ....

[...]

Excess revenues or losses

40 In fixing just and reasonable rates, tolls or charges ...,

(a) the Board may consider all revenues and costs of the owner that are in the Board's opinion applicable to a period consisting of

(i) the whole of the fiscal year of the owner in which a proceeding is initiated ...,
(ii) a subsequent fiscal year of the owner, or
(iii) 2 or more of the fiscal years of the owner referred to in subclauses (i) and (ii) if they are consecutive,

and need not consider the allocation of those revenues and costs to any part of that period,

> [...]
>
> (c) the Board may give effect to that part of ... any revenue deficiency incurred by the owner after the date on which a proceeding is initiated for the fixing of rates ... that the Board determines has been due to undue delay in the hearing and determining of the matter, and
>
> (d) the Board shall by order approve
>
> (i) the method by which, and
> (ii) the period, including any subsequent fiscal period, during which,
>
> any excess revenue received or any revenue deficiency incurred, as determined pursuant to clause (b) or (c), is to be used or dealt with.

***Public Utilities Board Act,* R.S.A. 2000, c. P-45**

> **Jurisdiction and powers**
>
> 36(1) The Board has all the necessary jurisdiction and power
>
> (a) to deal with public utilities and the owners of them as provided in this Act; ....
>
> (2) In addition to the jurisdiction and powers mentioned in subsection (1), the Board has all necessary jurisdiction and powers to perform any duties that are assigned to it by statute ....
>
> [...]
>
> **Fixing of rates**
>
> 89 The Board ... may ...
>
> (a) <u>fix just and reasonable</u> ... <u>rates</u> ...

<u>Chronology of Legislation</u>

[28] Some of the following discussion refers to judicial interpretations of predecessor legislation. An understanding of those decisions requires an appreciation of the interaction between the earlier and current legislation.

[29] Subsection 67(a) of the *Public Utilities* Act, R.S.A. 1955, c. 267 provided:

> 67. The Board ... may ...,
>
> (a) fix just and reasonable individual rates ....

[30] Section 67 of the *Public Utilities Act* was amended in April 1959 by S.A. 1959, c. 73, s. 9 as follows:

> (a) by renumbering the present section as subsection (1), ... [in other words, s. 67(a) became s. 67(1)]
>
> (d) by adding immediately after the renumbered subsection (1) the following subsections: ...
>
> (2) In fixing just and reasonable rates, ... the Board shall determine a rate base for the property of the proprietor ... and fix a fair return thereon.
>
> [...]
>
> (8) ... in fixing just and reasonable rates, the Board may give effect to such part of any excess revenues received or losses incurred by a proprietor after an application has been made to the Board for the fixing of rates as the Board may determine has been due to undue delay in the hearing and determining of the application.

[31] In 1960, the *Gas Utilities Act*, S.A. 1960, c. 37 was enacted and provided:

> **Powers of the Board**
>
> 27. The Board ... may ...
>
> (a) fix just and reasonable individual rates ...
>
> **Rate base**
>
> 28.(1) In fixing just and reasonable rates ... the Board shall determine a rate base for the property of the owner that is used or required to be used in his services to the public within Alberta and fix a fair return thereon.
>
> **Excess revenue or losses**

> 31. ... in fixing just and reasonable rates, the Board may give effect to such part of any excess revenues received or losses incurred by an owner of a gas utility after an application has been made to the Board for the fixing of rates as the Board may determine has been due to undue delay in the hearing and determining of an application.

[32] To summarize, the predecessor of present section 36 of the *Gas Utilities Act* (the power to set just and reasonable rates) is section 27 of the S.A. 1960 version of the *Gas Utilities Act*. The latter's predecessor is subsection 67(a) of the *Public Utilities Act* (later subsection 67(1)). The present section 37 of the *Gas Utilities Act* (fixing just and reasonable rates by determining rate base and fixing a fair return thereon) was section 28 in the S.A. 1960 version and it, in turn, was based on section 67(2) of the 1959 amendments to the *Public Utilities Act*. The predecessor to the present section 40 of the *Gas Utilities Act* is section 31 of S.A. 1960, which took its wording from ss. 67(8) of the 1959 amendments to the *Public Utilities Act*.

Discussion

[33] Calgary sees the central issue as the extent to which the Board can engage in retroactive ratemaking. ATCO says the appeal concerns an exercise of discretion by the Board. In my view, the appeal raises the following issues:

> (1) What is the source of the Board's jurisdiction over DGAs?
> (2) Did the Board retroactively change rates or did its decision have a prohibited effect?
> (3) What standard applies to this Court's review of the Board's decisions?
> (4) Against that standard, do the Board's decisions to allow ATCO to use the DGA to record transportation imbalances for 1999 to February 2004 warrant this Court's intervention?

The first two are threshold issues; if the decision under appeal falls because of the answer to either of them, the subsequent issues do not arise.

Issue 1. What is the source of the Board's jurisdiction over DGAs?

[34] Calgary acknowledges "the Board has jurisdiction to set up a DGA or what classes of costs or recoveries are to be included or how they are to be allocated.": Factum at para. 43. This Court implicitly approved the use of deferral accounts in regulated utility rate setting: *ATCO Electric Limited v. Alberta (Energy and Utilities Board)*, 2004 ABCA 215 at para. 26, 361 A.R. 1 ("*ATCO Electric*").

[35] That said, it is critical to identify the source of the Board's jurisdiction over deferral accounts. If it is section 40 of the *Gas Utilities Act*, time limits apply. If, as ATCO argues, it is sections 36 and 37, that legal impediment disappears.

A. Nature and Function of Deferral Accounts in Utility Regulation

[36] A consideration of the nature and function of deferral accounts provides context:

> Deferral accounts allow a utility to accumulate variances between a utility's approved rate based on forecasted costs and the utility's actual costs for a given period. Typically, at the end of the period, a utility will then collect from customers through a rate rider any balances in the deferral accounts owing by them and refund any balances owing to them.
>
> *ATCO Electric* at para. 26.

> In Alberta, utilities are usually regulated using a future test year regulatory framework in which the Board approves a forecast of a utility's revenue requirements that equates to a forecast of its future costs. However, if the Board is unable to determine a just and reasonable forecast, deferral accounts may be established to deal with uncertain items. In this case, due to the inability to accurately forecast pool prices, deferral accounts were created for 1999 and 2000 ...
>
> *Epcor Generation Inc. v. Alberta (Energy and Utilities Board*), 2003 ABCA 374 at para. 2, 346 A.R. 281 ("*Epcor*").

> [D]eferral accounts ... are accepted regulatory tools, available as a part of ... rate-setting powers ... [they] ...'enabl[e] a regulator to defer consideration of a particular item of expense or revenue that is incapable of being forecast with certainty for the test year' [citation omitted]. They have traditionally protected against future eventualities, particularly the difference between forecasted and actual costs and revenues, allowing a regulator to shift costs and expenses from one regulatory period to another.
>
> *Bell Canada v. Bell Aliant Regional Communications,* 2009 SCC 40, [2009] 2 S.C.R. 764 at para. 54 ("*Bell Aliant*").

[37] To summarize to this point, descriptions of the general purpose of deferral accounts and the history of this DGA shows that DGAs in gas utility regulation exist to ensure that consumers pay the cost of the gas they consume, with no resulting profit or loss to the utility's shareholders. This general objective has been fully supported by the courts: *ATCO Electric, Epcor, Bell Aliant, City of Edmonton, infra.*

B. Source of the Board's Authority

[38] What, then, is the source of the Board's jurisdiction to permit the use of DGAs as a regulatory tool? As outlined above at para. 3, the DGA at issue was approved in 1988. Nevertheless,

before 1988 the Board employed tools with a similar function to regulate gas utilities. Judicial views about the source of the Board's authority to use those tools are instructive.

[39] In the late 1950s the Board proposed a "purchased gas adjustment clause". It would permit the utility to recoup from consumers in the future amounts the utility had to pay for gas that proved more expensive than the utility's estimates, and to refund amounts to consumers if the estimates proved to be greater than the actual cost: *City of Edmonton et al. v. Northwestern Utilities Ltd.*, [1961] S.C.R. 392 at 396-397, 28 D.L.R. (2d) 125 ("*City of Edmonton*"). The Board's jurisdiction to approve such a device was upheld by the Supreme Court, which said that its purpose was to:

> ensure that the utility should from year to year be enabled to realize, as nearly as may be, the fair return mentioned in [s. 67(2)] and to comply with the Board's duty ... to permit this to be done. <u>How this should be accomplished...was an administrative matter for the Board to determine ... under the powers ... to fix just and reasonable rates which would yield the fair return mentioned in s. 67(2)</u>.

Id at 406-407 with emphasis added.

The counterparts to the section referred to in this passage are the present sections 36(a) and 37 of the *Gas Utilities Act*.

[40] In *Bell Aliant*, the telecommunication regulator, the Canadian Radio Television and Telecommunications Commission's ("CRTC") source of authority to establish deferral accounts was held to be the combined effect of sections 27 and 37(1) of the *Telecommunications Act*, S.C. 1993, c. 38: para. 37. Section 27(1) concerns setting just and reasonable rates, while section 37(1) permits the CRTC to require carriers to adopt any method of identifying the costs of providing services and to adopt any accounting method. The Court added that the "guiding rule of rate-setting under the *Telecommunications Act* is that the rates be 'just and reasonable', a longstanding regulatory principle.": para. 30. The authority to establish the accounts "necessarily includes the disposition of the funds they contain.": *Ibid*.

[41] These cases suggest that the Board's authority over DGAs flows from its power to set just and reasonable rates and a fair rate of return on rate base found in sections 36 and 37 of the *Gas Utilities Act*. Underlying that mandate is the "regulatory compact":

> Under the regulatory compact, the regulated utilities are given exclusive rights to sell their services within a specific area at rates that will provide companies the opportunity to earn a fair return for their investors. In return for this right of exclusivity, utilities assume a duty to adequately and reliably serve all customers in their determined territories, and are required to have their rates and certain operations regulated.

ATCO Gas & Pipelines Ltd. v. Alberta (Energy & Utilities Board), 2006 SCC 4, [2006] 1 S.C.R. 140 ("*Stores Block*") at para. 63.

[42] I agree with ATCO that the Board's authority over DGAs does <u>not</u> come from section 40. Although that provision uses broad language, its function is limited. It permits, among other things, consideration of utility's revenues and costs for the whole fiscal year in which an application for rates is made. It also authorizes adjustments for regulatory lag, that is, the difference between rates the utility seeks when its general rate application is made, and those appropriate when the rates are approved. But it does not limit the Board's general authority to employ other tools (such as the gas purchase adjustment clause and DGAs) that assist in the discharge of its obligation to set just and reasonable rates.

[43] It is worth repeating that this principle flows from *City of Edmonton*, where the Supreme Court considered the newly enacted section 67(8) of the *Public Utilities Act* (section 40's predecessor) in conjunction with the recovery of 1959 transitional losses which arose as a result of the 15-month delay between the utility's rate application (June 1958) and the rate approval (September 1959). As to the second issue before the Court, the Board's jurisdiction to permit the establishment of the gas purchase adjustment clause (the DGA's predecessor), the Court referred to "s. 67(2) of the 1959 amendment" (which the Court of Appeal found did <u>not</u> grant the Board the necessary jurisdiction to permit the gas purchase adjustment clause) and held at 407 (emphasis added):

> With great respect, however, <u>the proposed order</u> [establishing the gas purchase adjustment clause] <u>would be made in an attempt to ensure that the utility should from year to year be enabled to realize, as nearly as may be, the fair return mentioned in that subsection and to comply with the Board's duty to permit this to be done</u>. How this should be accomplished, when the prospective outlay for gas purchases was impossible to determine in advance with reasonable certainty, was an administrative matter for the Board to determine, in my opinion. This, it would appear, it proposed to do in a practical manner which would, in its judgment, be fair alike to the utility and the consumer.
>
> ... the Board ... propose[s] to make the order under the powers given to it and the duty imposed upon it by the sections to which I have referred to fix just and reasonable rates which would yield the fair return mentioned in s. 67(2).

[44] Calgary argues against reliance on sections 36 and 37 as the source of the Board's authority because of the Supreme Court's admonition against employing general statutory authority to ground the exercise of overly-broad Board powers, see e.g., *Stores Block* at para. 50. Elsewhere in the same decision, however, the Court emphasized the need to determine whether the exercise of the proposed power is a "practical necessity for the regulatory body to accomplish the object prescribed by

legislation": para. 77. According to the majority, such necessity was lacking in *Stores Block*. Here, for reasons outlined above at paras. 36-37, the use of DGAs is required if the Board is to regulate utilities effectively. Moreover, in *Bell Aliant*, Abella J. explained at paras. 51 - 53 that *Stores Block* did not "preclude the pursuit of public interest objectives through rate-setting". She contrasted *Stores Block* by pointing out that in *Bell Aliant*, the CRTC's rate-setting authority and its ability to establish deferral accounts for that purpose were at the very core of its competence. The same holds true in this case.

Issue 2. Did the Board retroactively change rates or did its decision have a prohibited effect?

[45] Calgary argues that by permitting ATCO to use the DGA to make adjustments going back several years the Board engaged in prohibited ratemaking because, in the result, ATCO's present consumers must make up for a past shortfall. I do not agree. I have already explained why I think its power to set just and reasonable rates allowed it to authorize the use of DGAs. It follows that its further orders about *how* to use a DGA did not constitute prohibited ratemaking. As discussed at paras. 69-71, however, this does not mean that the effect of its decision on future ratepayers is irrelevant in determining whether the Board reasonably exercised its powers over the DGA.

[46] A brief overview of some central principles of ratemaking, including the related concepts of retroactive and retrospective ratemaking, is necessary. Generally, ratemaking and rates must be prospective: *Coseka Resources Ltd. v. Saratoga Processing Co.* (1981), 31 A.R. 541 at para. 29, 16 Alta. L.R. (2d) 60 (C.A.). A utility's past financial results can be used to forecast future expenses, but a regulator cannot design future rates to recover past revenue deficiencies: *Northwestern Utilities Ltd. and al. v. Edmonton*, [1979] 1 S.C.R. 684 at 691 and 699 ("*Northwestern Utilities*").

[47] Retroactive ratemaking "establish[es] rates to replace or be substituted to those which were charged during that period": *Bell Canada v. Canada (Canadian Radio-Television and Telecommunications Commission*), [1989] 1 S.C.R. 1722 at 1749 ("*Bell Canada 1989*"). Utility regulators cannot retroactively change rates (*Stores Block* at para. 71) because it creates a lack of certainty for utility consumers. If a regulator could retroactively change rates, consumers would never be assured of the finality of rates they paid for utility services.

[48] Retrospective ratemaking, in contrast, imposes on the utility's current consumers shortfalls (or surpluses) incurred by previous generations of consumers. It is generally prohibited because it creates inequities or improper subsidizations as between past and present consumers (who may not be the same). "[T]oday's customers ought not to be held responsible for expenses associated with services provided to yesterday's customers": Yvonne Penning, "*The 1986 Bell Rate Case: Can Economic Policy and Legal Formalism be Reconciled*" (1989), 47(2) U.T. Fac. L. Rev. 607 at 610. This is sometimes referred to as the problem of inter-generational equity (which the Board discusses at p. 12 of the Limitations Decision reproduced at para. 23).

[49] Sometimes *retrospective* ratemaking is referred to as *retroactive* ratemaking. This is because rates imposed on a future generation of consumers, while prospective, create obligations in respect of past transactions, and in this sense they are retroactive: *City of Edmonton* at 402.

[50] In this case, the proposed accounting adjustments had retrospective effect: past costs would be borne by ATCO's present southern Alberta consumers, not the 1999 - 2004 consumers who received gas utility services when ATCO's gas costs were incurred.

[51] In summary, whether termed retrospective or retroactive ratemaking, imposing gas cost shortfalls or surpluses incurred by past consumers on future consumers is generally prohibited. Although this prohibition against retroactive and retrospective ratemaking is relatively clear, how to apply it in practice is less so. A review of key cases illustrates the complexity.

[52] A one-time credit order for consumers was upheld despite the fact that it was "retrospective in the sense that its purpose is to remedy the imposition of rates approved in the past and found in the final analysis to be excessive": *Bell Canada 1989* at 1749. Although the Board's review was retrospective in manner, the credit order was approved through an adjustment to interim rates. The Supreme Court stressed that the regulator had consistently stated its intention to review the interim rates: at 1755. Gonthier J. stated at 1752:

> ... one of the differences between interim and final orders must be that interim decisions may be reviewed and modified in a retrospective manner by a final decision. It is inherent in the nature of interim orders that their effect as well as any discrepancy between the interim order and the final order may be reviewed and remedied by the final order... the words "further directions" do not have any magical, retrospective content. ... <u>It is the interim nature of the order which makes it subject to further retrospective directions</u>. [emphasis added]

[53] In *Bell Aliant*, the Supreme Court also upheld a CRTC decision to order the disposition of funds that had accumulated in a deferral account. The Court rejected the argument that this constituted retrospective rate-setting because the rates had already been finalized. Abella J. pointed out that it was known at the outset that the CRTC would make subsequent orders about how to use the balance in the deferral accounts. At para. 63 she added (citations omitted and emphasis added):

> In my view, the <u>credits ordered out of the deferral accounts in the case before us are neither retroactive nor retrospective. They do not vary the original rate as approved, which included the deferral accounts, nor do they seek to remedy a deficiency in the rate order through later measures, since these credits or reductions were contemplated as a possible disposition of the deferral account balances from the beginning</u>. These funds can properly be characterized as encumbered revenues, because the rates always remained subject to the deferral accounts mechanism established in the Price Caps Decision. <u>The use of deferral accounts therefore</u>

> precludes a finding of retroactivity or retrospectivity. Furthermore, using deferral accounts to account for the difference between forecast and actual costs and revenues has traditionally been held not to constitute retroactive rate-setting ...

[54] Calgary argues that cases such as *Bell Canada 1989, Coseka* and *Bell Aliant* are distinguishable. The first two involved interim rather than final rates. In *Coseka*, it was pointed out at para. 36 that consumers must be aware that interim rates may be subject to change. As for *Bell Aliant*, all the parties knew in advance that the telecommunications companies would be obliged to use the balance of the deferral accounts in accordance with subsequent regulatory decisions: para. 61.

[55] Calgary suggests that gas rates here had long been finalized because the DGA had been reconciled in accordance with the Board's earlier orders that required forecast and actual gas costs to reconciled on a three-month rolling basis (see Decision 2001-75 at p. 64). It adds that when the seasonal or monthly DGA/GCRR process was approved it was not expressed to involve interim rates, therefore by definition the rates must be final: Factum at para 67.

[56] In *Epcor* Fruman J.A. opined that whether deferred accounts are interim or final depends on the facts: para. 15. The material before the Court makes such a determination impossible. Language in the 1988 decision quoted above at para. 4 suggests that the use of the DGA involved interim rates, but that language is vague. In the DGA Decision, the Board noted in section 4.2 ATCO's argument that deferral accounts are by nature interim and therefore not retroactive. Unfortunately, the Board did not express its views on this topic.

[57] Both *Bell Canada 1989* and *Bell Aliant* (which concerned deferral accounts rather than interim rates) illustrate the same preoccupation: were the affected parties aware that the rates were subject to change? If so, the concerns about predictability and unfairness that underlie the prohibitions against retroactive and retrospective ratemaking become less significant.

[58] Were these parties aware that gas rates were potentially subject to change through the use of the DGA? If so, whether the rates are characterized as interim or final, the principles in *Bell Aliant* govern.

[59] The history of DGAs demonstrates that affected parties knew they would be used from time to time to alter gas rates based on later, actual gas costs. Indeed, the Board so found as a fact in the Limitations Decision at p. 4. It adopted the reasoning from that decision in the Reconsideration Decision. The Board's fact findings are not appealable: *Alberta Energy and Utilities Board Act*, s. 26(1).

[60] Reconciliation of the DGA/GCRR would sometimes benefit consumers and sometimes not. Gas rates sometimes changed because of the lack of predictability (volatility) in gas prices and sometimes from other factors such as measuring errors. Whatever the cause, the objective was to ensure that the consumer paid the actual cost of the gas. This legitimate object was accepted by all

parties. It strengthened the utility regulatory system by ensuring that the utility received a fair rate of return on its rate base.

[61] Therefore, whether the rates should be characterized as final or interim, the use of the DGA in this case did not involve prohibited ratemaking.

Issue 3 - What standard applies to this Court's review of the Board's decisions?

[62] The conclusion that the Board had jurisdiction to make the orders about the use of the DGA, and did not thereby engage in prohibited ratemaking, suggests that the reasonableness standard of review should be applied.

[63] Abella J. employed this standard in *Bell Aliant* because, in her view, the issues went to the heart of the CRTC's specialized expertise, "the methodology for setting rates and the allocation of proceeds derived from those rates, a polycentric exercise with which the CRTC is statutorily charged and which it is uniquely qualified to undertake.": para. 38, see also para. 56. The same point applies here.

[64] Reinforcing this conclusion are the reasons given for applying the reasonableness standard in *ATCO Gas and Pipelines Ltd. v. Alberta (Energy and Utilities Board)*, 2008 ABCA 200, 433 A.R. 183 at paras. 15 - 18 (leave to appeal refused [2008] S.C.C.A. No. 347). See also *ATCO Electric*, where the Court determined in its standard of review analysis that "[w]ith ... the widespread use of deferral accounts, determining the appropriate methodology to be used in calculating prudent costs of financing these deferral accounts engages the Board's specialized expertise.": para. 63. Reasonableness is also the standard applied to a gas regulator's decision to permit a utility to recover material and previously unrecorded costs for the provision of gas services: *Natural Resource Gas Ltd. v. Ontario (Energy Board*) (2006), 214 O.A.C. 236, 149 A.C.W.S. (3d) 889.

Issue 4. Has the reasonableness standard been breached ?

[65]

> Reasonableness is a deferential standard ... A court conducting a review for reasonableness inquires into the qualities that make a decision reasonable, referring both to the process of articulating the reasons and to outcomes. ... [R]easonableness is concerned mostly with the existence of justification, transparency and intelligibility within the decision-making process. But it is also concerned with whether the decision falls within a range of possible, acceptable outcomes which are defensible in respect of the facts and law.

Dunsmuir v. New Brunswick, 2008 SCC 9, [2008] 1 S.C.R. 190 at para. 47.

In my view, this standard has been breached.

[66] The Board's sole justification for permitting ATCO to recoup eighty-five percent of the gas costs it sought from present consumers is found in the following passage of the DGA Decision at p. 11:

> ... the Board must remain mindful of the essential nature of the DGA as a deferral account and the allowances in the past of certain prior period adjustments spanning a number of years. Accordingly, the Board is inclined to allow [ATCO] substantial recovery of the applied for prior period adjustments.

Stripped to its essentials, two reasons emerge: the nature of the DGA as a deferral account and the fact that the DGA had been used in the past to make adjustments over several years.

[67] Presumably the "nature of the DGA" point refers to the Board's historical assessment of the DGA contained in section 2.3, entitled "Nature of DGA Adjustments & Recovery Period". In that section, the Board examined the purpose of the DGA when approved in 1988: "reconciling actual costs of gas incurred by a utility with forecasts that it used in setting a GCRR, i.e. the rate it used to recover the commodity costs of gas from sales customers." In describing the change made in 2001 (altering the reconciliation period from a seasonal to a monthly basis), the Board repeated that the purpose of DGA adjustments was "to allow for forecasting inaccuracies, relative to the timing of actual gas acquisition costs incurred". It is manifest that the costs approved in the decisions under appeal did not fall within the original purpose of the DGA, namely, adjusting for gas price volatility.

[68] That brought the Board to its second point, that "during the approximate 16 years that the DGA has been in place, it has been used to update adjusted imbalance amounts from shippers, producers and interconnecting pipelines.": *Id* at p. 10. Usually those adjustments were made within a reasonable time, although sometimes the periods exceeded one year. This observation boils down to "we previously permitted adjustments over longer periods, so we will do so here".

[69] Set against these two rationales for granting the bulk of ATCO's application are the Board's many other comments:

- DGAs have evolved into a vehicle to fix all possible gas cost errors and pass them on to consumers;
- when first implemented reconciliations of the DGA were not expected to go back further than 12 months. Longer periods were sometimes accepted under special circumstances
- the DGA "was never set up with the intention of permitting all prior period accounting errors, particularly those that would have been subject to ATCO's management and control";
- accounting errors should typically be absorbed by the utility's shareholders;
- the DGA should not be treated as a catch-all for fixing errors, including those with a long history or resulting from human error, when adequate processes have not been in place to capture and correct the problem at an early stage;
- seven years represents a significant lag presenting obvious inter-generational equity issues;

- ATCO had an onus to ensure the System was working properly and was providing correct data;
- it did not appear that ATCO implemented an appropriate and timely review process for System design;
- there was no evidence of actual internal or external audits being performed to ensure the design was valid as the System was being put into service; and
- between 1998 and 2002 there was a lack of oversight by ATCO to test and develop appropriate controls to ensure that the System output generated was as intended.

[70] Mirroring these observations were the Board's reasons for concluding that ATCO should bear fifteen percent of the costs claimed:

- it doubted whether it could rely on ATCO's revised imbalance amounts;
- little on the record demonstrated the extent to which the numbers were faulty, perhaps partly because of ATCO's unilateral actions in destroying data;
- there was no demonstration that the System report was adequately tested at the time of inception;
- the System lacked audits;
- ATCO lacked adequate internal controls and supervisory systems;
- there was inadequate proof of corrections and opening balances; and
- there was a lengthy delay in discovering the errors.

[71] In summary, the Board's own analysis highlights the accumulation of factors that make unreasonable its decision to allow ATCO to recover eighty-five percent of the transportation imbalances through the DGA. Unlike most previous uses of DGAs, these charges did not result from gas price volatility. Nor did they resemble other past uses of DGAs where errors were attributable to measuring equipment problems and where there had been no suggestion of utility fault. Here the failure to levy appropriate gas charges was entirely due to deficiencies within ATCO's own system, exacerbated by a long delay in discovering the problem. ATCO's destruction of data made data verification impossible. As a result of the delays, at least some who were not consumers when the problems originated would have to absorb the costs of ATCO's carelessness. Even though this was not prohibited ratemaking *per se*, the long delays gave rise to inter-generational equity issues which lie at the heart of the prohibition against retrospective ratemaking.

[72] As outlined in para. 9, previous DGA decisions took account of matters such as the amount of the adjustment, the timeliness of the application, the extent to which the utility acted responsibly, foreseeability of the problem, and whether consumers who received the service would bear the cost of the adjustment. When such factors are applied to this case, it is apparent why the Board's decision is not defensible on its facts.

[73] As the Board intimated, there are compelling reasons why this sort of loss should be borne by shareholders rather than long-after-the-fact consumers. Shareholders have the ability to control

or at least influence ATCO's management practices. Consumers do not. Requiring consumers rather than shareholders to bear most of the loss does not encourage utilities to conduct operations in a careful, time-sensitive way. The Board itself appropriately observed at p. 5 of the DGA Decision that allowing ATCO (full) recovery "could be considered ... a reward for poor management".

[74] The Board's Limitations Decision at least partly addresses the above concerns because it generally limits DGA claims to a two-year period, except in special circumstances not within the utility's control. That decision is not subject to appeal and it would be inappropriate to comment on it further here. Nevertheless, it seems unlikely that the present DGA adjustments would have passed muster under the Board's criteria in the Limitations Decision.

Procedural Matters

[75] I agree with Côté J.A's suggestion at para. 238 that the efficient disposition of an appeal can be hindered if parties neglect to provide sufficient copies of Extracts of Key Evidence in appeals like this that require only one copy of the Tribunal's record to be filed. In this case, that difficulty was largely alleviated because the key Board decisions were included in the parties' Books of Authorities.

Conclusion

[76] The appeal is allowed, the orders under appeal vacated and the matter returned to the Board for consideration in accordance with these reasons.

Appeal heard on January 13, 2010

Reasons filed at Calgary, Alberta
this 23rd day of April, 2010

Hunt J.A.

I concur:

Authorized to sign for: Paperny J.A.

**Reasons for Judgment Reserved of
The Honourable Mr. Justice Côté
Concurring in Part**

A. Introduction and Issues

[77] This is an appeal from what was the Alberta Energy and Utilities Board, the rate-regulating tribunal for natural gas utilities. (Its name has changed over the years and is not up-to-date in the style of cause, but I will call it "the Commission".) The issue is whether that tribunal could let the utility company recover a lump sum from present consumers because of mistakes in accounting for past gas purchases by the utility company extending back about six years.

[78] Here is an overview of this judgment. Part B describes the odd and lax way in which the respondent utility's problem arose, and the Commission's three decisions about how to handle the utility's ensuing request, and agrees that the Commission's treatment is unreasonable. Part C describes how the Supreme Court of Canada and our Court of Appeal have consistently interpreted the governing statutes and barred retroactive rate-making; and the very limited amendments which the Legislature made in response. Part D describes Alberta's rate-making procedure and law, and shows how the decision under appeal is illegal because retroactive. Part E shows how the deferral accounts used here were created for very different purposes and long since reconciled, remaining almost by oversight. Part F describes the recent ***Bell*** decision and how it does not apply here. Part G similarly distinguishes two other decisions. Part H is about the standard of review. Part I is about the conclusion and remedy, and Part J makes some requests about procedure.

B. Facts

1. ATCO Finds Significant Error

[79] An outsider might suppose that it would not be particularly difficult for a gas public utility to keep track of how much gas it bought, sold or transported, particularly when it does not store any significant amount. Similarly, one supposes that the utility would have accounting records reliably keeping track of what it paid for the various amounts of gas which it got. This case suggests that at some times and places it may not be that easy or straightforward.

[80] One reason might be that the respondent ATCO divides its operations. A second reason may be that gas supply to consumers in Alberta has become more complex in the last generation. No longer is the owner of a pipe necessarily the owner of the gas flowing through it, and no longer is the owner of a local gas distribution pipe running under a street necessarily the vendor of the gas being bought by the consumers located on that street.

[81] The Commission found a bigger third reason. ATCO had set up some inappropriate accounting systems to handle this situation, inconsistently administered them for years, and throughout made inadequate checks of their operation or adequacy. The Commission so finds in its 2005 decision (pp. 4-5, 7-8, 11-12 A.B. pp. F7-8, F10-11, F14-15).

[82] For many years, ATCO seems not to have realized the depth of these problems. Helped by some gentle prodding by the Commission in late 2003, ATCO and its outside accountants investigated their accounting problem more deeply. By early 2004, they recognized fairly serious accounting errors that ATCO had made in northern Alberta for all of the years 1998, 1999, 2000, 2001, 2002, 2003, and for early 2004. In the south, the problem started a year later than in the north, but also lasted until early 2004.

[83] The amounts were significant. ATCO's recalculations suggested that in southern Alberta its gas costs from 1999 to 2004 had in fact been a total of $11.6 million higher than it had recorded in any of its books or its regular filings with the Commission. In the north, they were almost $2 million lower for 1998 to 2004.

[84] In its first (2005) decision on the subject, the Commission (then the Alberta Energy and Utilities Board) explained the errors as follows.

> AG [ATCO Gas] submitted that there were two distinct aspects of imbalances: the management, control and reporting of other gas owners' imbalances that result from the shipment of other owners' gas through the pipeline network (collectively referred to herein as Transportation Processes), and the recognition of the effect that other gas owners' imbalances have on regulated gas supply procurement and the timing of cost recovery from regulated sales customers (DGA/GCRR Processes).
>
> AG submitted that other gas owners' imbalances were made up of transportation imbalances and exchange imbalances. Transportation imbalances are associated with active transportation contracts, which reflect the physical movement of gas through ATCO's pipeline system. AG described Transportation Processes as including, without limitation, measurement, nomination, allocation, reporting, preparing statements, invoicing and receiving payment from other gas owners who contract for transportation service. AG also noted that exchange imbalances are those associated with active exchange contracts, which reflect a physical swap of gas between ATCO and a counterparty and in which there are no monthly imbalance settlement provisions. (§ 2.1, p. 3, A.B. p. F6)

* * *

> The Board [now the Commission] agrees with AG that this Application concerns the disconnection that occurred between the true and correct imbalances reported in the Transportation Processes. . . .
>
> (*id.* at p. 4, A.B. p. F7)

* * *

> . . . In addition, the Board notes that ATCO did not appear to take the appropriate action to modify the functionality of the TIS system with respect to Rate 11 delivery input which ultimately led AP [ATCO Pipelines] employees to input inaccurate delivery data in order to 'quiet' an error message.
>
> (*id.* at p. 5, A.B. p. F8)

2. ATCO Proposed to Pass on the Shortfall

[85] As a result of its belated discoveries, ATCO filed with the Commission's predecessor Application #1347852 of May 31, 2004. ATCO proposed a simple solution: to make ATCO's problem the consumers' problem. The rates for gas delivered from 1998 to 2003 had long since been fixed, charged, and paid, and the gas in question long since sold, delivered, billed, and paid for. Yet ATCO now wanted to turn its old long-undiscovered $11.6 million southern shortfall into a new additional lump-sum charge to present southern customers. Conversely, ATCO volunteered to give a rebate of almost $2 million to present northern customers.

3. The Commission's Three Decisions

[86] The Commission responded to ATCO's "error-correction" application in three decisions.

(a) "Imbalance Adjustments" April 2005 Decision # 2005-036

[87] In this decision, the Commission made fact-findings about the causes of the errors, which findings are not challenged on appeal by Calgary or ATCO. They reveal ATCO's multifold and long-lasting accounting inadequacies (pp. 7-8, 12 A.B. pp. F10-11, F15). The Commission found as follows:

> . . . The Board [now the Commission] considers that the error in the design of the TIS Report along with the management practices related to process control, including those related to the TIS Report, are of concern.

> . . . The Board, however, notes a lack of documented audit evidence that would support the correctness of the imbalances reporting systems in the present case, and is thus concerned with the degree of accuracy that AG [ATCO Gas] contends exists for the present imbalances adjustments. Moreover, the Board is concerned with the amount of time, dating back to 1998, that it took ATCO to find, and ultimately make, the imbalances corrections.
>
> (2005 decision, p. 4, A.B. p. F7)
>
> The Board is troubled by what it considers to be **an apparent lack of diligence exhibited by either of AG or AP or both** of them over the reporting of imbalances in as much as the errors included in the review had occurred since at least 1998.
>
> (*id.* at p. 5, A.B. pp. F8, Emphasis added)
>
> * * *
>
> . . . The Board notes that AG stated in the Application that "ATCO found that the original design specification for the monthly TIS Report was not correct." This acknowledgment would indicate that before the imbalances problem was identified there had been a **lack of system control over, and audit of, the design**.
>
> . . . It appears to the Board that if AP employees had not entered the inaccurate Rate 11 delivery data, the incorrect TIS Report may not have been noticed by AG in the normal course of business, given that **it does not appear that ATCO tested or planned to test the integrity of the report** . . .
>
> (*id.* at p. 5, A.B. p. F8, Emphasis added)

[88] Yet the Commission did little about the utility's various longstanding accounting inadequacies. It merely deducted 15% as a penalty for them. Subject to that deduction, the Commission did as ATCO asked; it ordered the current southern customers to top up ATCO's profits by an amount equal to ATCO's past bookkeeping errors for those five or more past years.

[89] The Commission also allowed ATCO to give the current northern customers a rebate. The Commission did not mention the suggestion that the northern refund bear interest for all the years the utility company had had the funds (January 21, 2005 argument, Commission Record Tab 47, p. 29). Instead, the Commission did the reverse: it dictated that that consumer rebate would be **reduced** by 15% (p. 12, A.B. p. F15). There was no explanation for the reduction, and I cannot think of any logical one. It might have been the Commission's desire for aesthetic facial symmetry between north and south. It seems most unlikely that the Commission intended to penalize the northern consumers for ATCO's shortcomings. Maybe it was just an oversight. After various adjustments, on August 23,

2005 the Commission fixed the northern refund at $541,000, and the leave to appeal does not cover the northern errors or rebate. No one in the north has appealed.

[90] The Commission noted that since 1987, ATCO has maintained a deferral account. It was originally set up to allow quick reconciliation of unpredictable fluctuating future gas purchase cost estimates, with actual costs for the same period. The Commission said the purpose for the account has nothing to do with the type of errors in question here, and that the accounts were never designed for purposes such as the current errors. See Part E below for details and citations.

[91] Though all the reconciliations of that deferral account had been completed years before, the Commission decided that the new error charge (and rebate) described above would be done through or because of that deferred account.

[92] Apart from background and recitals, the actual reasoning of the Commission in this 2005 decision was brief, and contained little or no explanation beyond that summarized here.

[93] In particular, these 2005 reasons said nothing about the rule against retroactivity, nor whether the governing legislation permits this sort of retroactive adjustment (going back some six or so years). However, the Commission did seem to suggest that such steps are retroactive rate adjustment for past years' errors: (2005 decision, § 2.8, first para., p. 14, A.B. p. F17).

[94] It is probably idle to speculate on the reasons for that significant omission.

[95] The Commission's later 2008 Decision says that no one raised the rule against retroactivity during this first (2004) application (2008 Decision §4.3, p. 7, A.B. p. F31). The Commission may have got that idea from allegations in ATCO's October 5, 2007 argument (Commission Record on present appeal, Tab 60, pp. 2, 5, 6). ATCO also alleged the same thing to this Court in 2007: see ATCO's February 22, 2007 factum filed for that previous appeal (pp. 1, 4, 7, 8, 9, 11; cf. p. 10). And cf. similar allegations in the Commission's February 21, 2007 factum (pp. 5, 6). The Commission evidently did not recall its own file (though its 2004-2005 record was consolidated with its 2007-2008 record).

[96] In fact, the various statements by ATCO and by the Commission alleging Calgary's silence are not correct. Calgary **did** argue the retroactivity issue during the first hearing, especially in its reply written argument of January 28, 2005 (Tab 50 of the Commission's Record). See especially pp. 2-3, quoting s. 40 of the *Gas Utilities Act*, the key legislation. The date, application number, and title of that written argument all confirm that it was filed for this first application which led to this first Commission decision in April 2005. The Commission's 2008 decision says that all argument to the Commission on this first 2004-2005 application had been written, not oral (pp. 2-3, A.B. pp. F5-F6).

[97] ATCO's inaccurate allegations of Calgary's silence are puzzling. Maybe counsel relied on memory alone. Maybe they interpreted Calgary's written 2004-2005 argument in some unreasonable narrow fashion. And ATCO's 2007 factum may have used terms like "jurisdiction" in a narrow way (e.g. excluding non-jurisdictional Calgary arguments). (See Part D.9. below.) In any event, this is an appeal from the Commission's rehearing, and the "alleged silence" point no longer influences the result (if it ever did).

[98] The City of Calgary sought leave (May 30, 2005) and got leave (July 6, 2006: see 2006 ABCA 180) to appeal from this 2005 Commission decision. The Court of Appeal allowed the appeal. It said the question could not be decided on the record before the court, doubtless relying on ATCO's erroneous factum. The Court sent the matter back to the Commission to rehear and to reconsider: see 2007 ABCA 133, 404 A.R. 317.

[99] On August 23, 2005, the Commission gave decision 2005-093 approving ATCO's computation of the precise amounts ATCO would collect and refund under the April 2005 decision.

(b) "Limitation Period" May 2006 Decision #2006-042

[100] Meanwhile, the Commission itself was properly troubled by the implications of its 2005 precedent. If carried to its logical extreme, it could leave gas rates charged to consumers and payments by past customers forever open to alteration, approaching the lengthy uncertainties in Lord Eldon's Court of Chancery. The Commission therefore ordered a second application about whether the Commission should impose its own limitation period, maybe two years. (It proceeded under a further application which the Commission ordered ATCO to make.) Little was said about the existing limitation period (beginning of the fiscal year of application) found in the *Gas Utilities Act*, and described in Part C below.

[101] The Commission's decision on this limitation-period hearing was that the utilities statutes did not matter or apply, because of the old deferral account. So the Commission thought that the extent of retroactivity was more or less a matter of its own discretion. The Commission ordered that henceforth (not retroactively) there would sometimes be a new two-year limitation period for retroactive rate changes. I say "sometimes", because the two-year time limit would not apply where the adjustment sought was large and there were "special circumstances" not within the utility's control.

[102] It is not clear whether the "special circumstances" phrase referred to what caused the initial problem, or why the application was made after the expiry of two years.

[103] I note that ATCO's limitation-period application was filed after Calgary moved for leave to appeal from the Commission's first decision. And the Commission's reasons on that in May 2006 were almost a year after such leave was sought. The Commission likely knew of those events. But we have to look at the 2006 reasons because they are incorporated into the 2008 decision.

[104] ATCO filed a motion in the Court of Appeal for leave to appeal this 2006 decision, but by agreement that motion was adjourned from time to time over the years, and was never heard (see 2008 Commission decision, p. 1). That motion was discontinued recently (February 12, 2010). ATCO later argued before the Commission that Calgary's not trying to appeal this 2006 decision somehow estopped it from questioning the 2005 Commission decision which it has twice appealed (October 5, 2007 argument, p. 6, para. 12, Commission Record Tab 60). I cannot see the logic of that, nor do I recall any law to support it (and none was cited). In any event, no such argument was put to the Court of Appeal on this appeal.

(c) "Reconsideration" January 2008 Decision #2008-001

[105] This third Commission decision is the fruit of the rehearing directed by the Court of Appeal, as mentioned above (end of subpart (a)), and the consequent reconsideration application.

[106] The Commission refused to let Calgary file any more evidence, despite the Court of Appeal's 2007 direction. (That point is discussed further in Part E.4 below.)

[107] The Commission reached the same conclusion as it had in 2005. The key issue was retroactivity.

[108] Almost the only significant thing which the Commission said in 2008 about retroactivity was to quote what it had said on the subject in its 2006 limitations decision (subpart (b) above). That is two short paragraphs which read as follows:

> With regard to the issue of retroactive rate-making raised by Calgary, the Board [now the Commission] does not accept the position advanced by Calgary. The Board has broad discretion to set just and reasonable rates and, in the case of setting gas cost recovery and flow-through rates, sets these rates in accordance with the use of DGAs. In doing so, the deferral nature of the DGAs is specifically contemplated and acknowledged when the rates are set. Deferral accounts, by their nature, anticipate adjustments such as the ones at issue in this matter and, as such, cannot be said to constitute retroactive rate-making. The Supreme Court of Canada has approved the use of deferral accounts for gas and has further noted that such a mechanism is a purely administrative matter. In *Epcor Generation Inc. v. AEUB*, 2003 ABCA 374, the Alberta Court of Appeal adopted the same approach and stated that as the deferral account in issue in that decision was not closed, it was not a final order, and was not retroactive rate making or procedurally unfair.

> Consequently, the Board considers that a DGA has not been subject to any limitation regarding jurisdiction either by way of legislation, past Board decision or court ruling which would have prevented the Board from considering prior period adjustments to a DGA. In fact, the Board has dealt with prior period adjustments to DGAs since their inception in 1987, with the prior periods being of varying lengths.
> (p. 4 of 2006 decision, § 3.1 near end, and quoted on pp. 7-8 of 2008 decision, A.B. pp. F31-32)

A Commission footnote says that the Supreme Court of Canada approval referred to in the quotation is in ***Edmonton v. N.W.U.L.*** [1961] S.C.R. 391.

[109] I am not certain, but the Commission's next 2008 paragraph seems to be about retroactivity as well. So I quote it:

> The provisions of the GUA and PUBA relied on by Calgary authorize the Board [now the Commission] to take into account financial information for the whole of the year in which a tariff application is filed in the event that the Board intends to approve a tariff effective prior to the date on which the tariff application is made. The "prior period" is limited to some period in the calendar year before the date of the application, depending on when the application might be filed in the calendar year. Strictly speaking, deferral accounts are unnecessary to account for financial activity in this period, so the Board does not find Calgary's argument persuasive on this basis.
> (p. 8, A.B. p. F32)

One curious feature of that paragraph is discussed at the end of Part D.6 below.

[110] There is another paragraph in the decision immediately after that one. I am not entirely certain how to interpret it. It contains some assertions and conclusions. But the only actual reason which I can find in it is one. I read it as saying that the Commission has often acted this way, and if it refused to do so now, it would bring into question its previous decisions.

[111] To sum up, the basic real reason given by the Commission was the idea that a deferred account bypasses the ordinary rule against retroactivity.

[112] Martin J.A. gave leave to appeal this 2008 Decision (order of July 2, 2009). That is the present appeal.

4. Unreasonable Decision

[113] Hunt J.A. concludes that the Commission's decision here is unreasonable. I agree with that conclusion, and with the reasons which she gives for finding unreasonableness. Many other things discussed in my reasons would also help to support that conclusion.

C. Legislative History

1. Introduction

[114] The question of whether the impugned Commission decision violates the law forbidding retroactivity requires examining a number of aspects of the nature and policy of that law. I can best start with the history of the relevant legislation and the court decisions about it. That is what this Part C does.

[115] A half-century's dialogue between courts and the Legislature is outlined in subpart 2. It reveals a very clear picture. The courts found firm legislative limits which the Legislature adjusted only slightly, and otherwise confirmed, basically keeping them to the present day.

2. Chronology

(a) The *Public Utilities Act*, R.S.A. 1955 c. 267, s. 67 gave the Commission (then the Board of the Public Utilities Commissioners) general powers to fix utility rates, but said little express about time limits or retroactivity.

(b) March and August 1959 saw Commission decisions which were then appealed to the Court of Appeal, whose decision is described in (e) below.

(c) April 1959 the Legislature amended (c. 73, s. 9(d)) the *Public Utilities Act*, adding s. 67(8). Undue delay in hearing and deciding an application henceforth lets the Commission give effect to excess revenues or losses, incurred after filing a utility's rate application, when the Commission fixes just and reasonable rates.

(d) Legislature passed new *Gas Utilities Act* as 1960 c. 37. In its s. 31 has identical wording to the *Public Utilities Act* s. 67(8) just discussed (with one trivial exception).

(e) September 22, 1960 Appellate Division decided ***Edmonton v. N.W.U.L. (#2)*** 34 W.W.R. 241, considering items (b) and (c) above. The Supreme Court of Canada varied this decision on April 25, 1961 on other grounds (allowing a purchased-gas adjustment clause): [1961] S.C.R. 392, 34 W.W.R. 600. The Supreme Court of Canada held that utility rates must be based on an estimate of future expenses (p. 612 W.W.R.). It apparently accepted the proposition that until the 1959 amendment, the Commission had no power at all to make retroactive rates or allowances, not even for regulatory delay.

(f) Adoption of *Gas Utilities Act* R.S.A. 1970, c. 158, s. 31, which merely re-enacted 1960 c. 37, s. 31 (item (d) above) with no change.

(g) December 9, 1976: Appellate Division decided ***Northwestern Utilities v. Edmonton*** 2 A.R. 317. Its decision was not novel, and is similar to ***Calgary (City) v. Madison Nat. Gas Co.*** (1959) 28 W.W.R. 353, 360 (Alta. C.A.). The ***N.W.U.L.*** decision reversed a Commission decision, and held that unexpected shortfalls in revenue or unexpected expenses incurred by a utility before the date of the rate application cannot be considered (paras. 6, 25-26, 34). The Supreme Court of Canada affirmed the Appellate Division in late 1978: [1979] 1 S.C.R. 684, 12 A.R. 449. The Supreme Court explained the 1959 amendment: its scope is narrow.

(h) 1977: Legislature amended s. 31 of the *Gas Utilities Act*: see c. 9, s. 5(1), (2). That did not affect pending cases. Old s. 31 became new s. 31(c). The rest of the section was new.

(i) That new s. 31 (of 1977) became R.S.A. 1980, c. G-4, s. 32, with no significant change.

(j) That section became the present R.S.A. 2000, c. G-5, s. 40, with only minor changes in drafting style. The *Public Utilities Act*, R.S.A. 2000, c. P-45, s. 91 contains virtually identical words. Section 40 of the *Gas Utilities Act* now reads as follows:

> **40** In fixing just and reasonable rates, tolls or charges, or schedules of them, to be imposed, observed and followed afterwards by an owner of a gas utility,
>
> (a) the Board may consider all revenues and costs of the owner that are in the Board's opinion **applicable to a period** consisting of
>
> (i) the whole of **the fiscal year of the owner in which a proceeding is initiated for the fixing of rates**, tolls or charges, or schedules of them,
>
> (ii) **a subsequent fiscal** year of the owner, or
>
> (iii) 2 or more of the fiscal years of the owner referred to in subclauses (i) and (ii) if they are consecutive,

and need not consider the allocation of those revenues and costs to any part of that period,

(b) the Board may give effect to that part of any **excess revenue received or any revenue deficiency incurred** by the owner that is in the Board's opinion applicable to the **whole of the fiscal year of the owner** in which a proceeding is initiated for the fixing of rates, tolls or charges, or schedules of them, that the Board determines is just and reasonable,

(c) the Board may give effect to that part of any **excess revenue received or any revenue deficiency incurred** by the owner **after the date on which a proceeding is initiated for the fixing of rates**, tolls or charges, or schedules of them, that the Board determines has been **due to undue delay in the hearing and determining** of the matter, and

(d) the Board shall by order approve

(i) the method by which, and

(ii) the period, including any subsequent fiscal period, during which,

any excess revenue received or any revenue deficiency incurred, as determined pursuant to clause (b) or (c), is to be used or dealt with.

(Emphasis added)

(Presumably the last three lines should be indented more, but I quote them the way that they appear in the Revised Statutes of Alberta. The equivalent lines are indented more in the *Public Utilities Act*.)

3. Conclusion

[116] That legislative history shows that current s. 40 of the *Gas Utilities Act* is the Legislature's limited response to the decisions of the Court of Appeal and Supreme Court of Canada described above (in subpart 2). So the principle of the Court decisions has not changed. The only small change was that the time limits were extended slightly. Though **later** years' expenses or excess revenue can be considered (if they are consecutive), shortfalls or excesses in **previous** years' expenses or excess revenue are still off-limits (as always). Only shortfalls or excesses of revenues and costs back to the beginning of the fiscal year in which the application is filed, can be considered. That was the precise point in issue in the Court of Appeal decision of 1976 (and Supreme Court of Canada affirmation).

That is the only legislative amendment to the Court decisions. New para. (d) on methods and periods is vague, but seems to be purely ancillary (on which see the ***Stores Block*** decision discussed in Part D.5 below).

[117] Given this history, this Alberta legislation is incompatible with any Commission power to take into account to base, or adjust, rates on actual shortfalls or excesses of revenues or expenses in a year earlier than the year in which the application by the utility is filed.

[118] Precedent is not the only reason for such rules. The Supreme Court of Canada's and this Court's decisions are based on fairness, certainty and logic. That is explained further below in Part D, which describes those court decisions more fully.

D. The Decision Appealed is Retroactive

1. Introduction

[119] This Part D approaches the whole topic of retroactivity from several directions. All these subtopics interlock. Retroactivity cannot be properly described without showing the basics of setting utility rates.

2. Final Prospective Rate-Making

[120] There are two ways in which one could regulate how much consumers pay for gas from public utilities. The usual and traditional way is to have rates fixed for a period, at least part of which period is in the future. Then one forecasts all the likely expenses (including cost of capital), and sets rates accordingly. There is some risk to the utility company, as it may get fewer revenues or higher expenses than forecast (or both). Conversely, the company also enjoys the chance of making a higher profit, if costs are below forecast, or revenues higher than forecast. That is the traditional way of making utility rates. (See further subpart 6 below.)

[121] That is also the practice with respect to Alberta natural gas rates, and the law requires that procedure. The Supreme Court of Canada explains that clearly in ***N.W.U.L. v. Edm. (City)*** [1979] 1 S.C.R. 684, 12 A.R. 449, on pp. 452 ff. (A.R.). I quote from that judgment (using A.R. para. numbers):

> [4] The Board [now the Commission] is by the [Gas Utilities Act] directed to "fix just and reasonable . . . rates, . . . tolls or charges . . ." which shall be imposed by the Company . . . The Board then estimates the total operating expenses incurred in operating the utility for the period in question. The total of these two quantities is the 'total revenue requirement' of the utility during a defined period. A rate or tariff of rates is then struck which in a defined prospective

period will produce the total revenue requirement. The whole process is simply one of matching the anticipated revenue to be produced by the newly authorized future rates to future expenses of all kinds. Because such a matching process requires comparisons and estimates, a period in time must be used for analysis of past results and future estimates alike. . . . It is a process based on estimates of future expenses and future revenues. Both according to the evidence fluctuate seasonally and both vary according to many uncontrollable forces such as weather variations, cost of money, wage rate settlements and many other factors. . . .

* * *

[5] While the Statute does not precisely so state, **the general pattern of its directing and empowering provisions is phrased in prospective terms. Apart from s. 31 [now s. 40] there is nothing in the *Act* to indicate any power in the Board to establish rates retrospectively in the sense of enabling the utility to recover a loss of any kind which crystallized prior to the date of the application** (*vide: City of Edmonton et al. v. Northwestern Utilities Limited*, [1961] S.C.R. 392*, per* Locke J. at 401, 402).

[6] The rate-fixing process was described before this Court by the Board as follows:

> The PUB approves or fixed utility rates which are estimated to cover expenses plus yield the utility a fair return or profit. This function is generally performed in two phases. . . . The revenue required to pay all reasonable operating expenses plus provide a fair return to the utility on its rate base is also determined in Phase I. The total of the operating expenses plus the return is called the revenue requirement. In Phase II rates are set, which, under normal temperature conditions are expected to produce the estimates of "forecast revenue requirement". These rates will remain in effect until changed as the result of a further application or complaint or the Board's initiative. . . .

[7] The statutory pattern is founded upon the concept of the establishment of rates *in futuro* for the recovery of the total forecast revenue requirement of the utility as determined by the Board. The establishment of the rates is thus a matching process whereby

> forecast revenues under the proposed rates will match the total revenue requirement of the utility. It is clear from many provisions of *The Gas Utilities Act* that **the Board must act prospectively and may not award rates which will recover expenses incurred in the past and not recovered under rates established for past periods. There are many provisions in the *Act* which make this clear** . . . Section 32 likewise refers to rates "to be imposed thereafter by a gas utility".
>
> * * *
>
> [22] It is conceded of course that the Act does not prevent the Board from taking into account past experience in order to forecast more accurately future revenues and expenses of a utility. **It is quite a different thing to design a future rate to recover for the utility a 'loss' incurred or a revenue deficiency suffered in a period preceding the date of a current application. A crystallized or capitalized loss is, in any case, to be excluded from inclusion in the rate base and therefore may not be reflected in rates to be established for future periods**. (emphasis added)

See also Netz, "Price Regulation: a (Non-Technical Overview)", in *Encyclopedia of Law and Economics* 396 (2000), at 401-03. (A version of that paper is cited in the ***Stores Block*** decision of the Supreme Court of Canada, *infra*.)

[122] The word "losses" above is ambiguous. In such discussions of retroactivity, it does **not** have its ordinary meaning of a business not so much as breaking even and running at a loss. Instead, the "losses" referred to in this particular context mean actually making less money in a period than had been forecast for that period, because expenses proved larger than anticipated, or revenues proved smaller than anticipated. See ***N.W.U.L. v. Edmonton*** (1979), *supra* (p. 455 A.R. para. 10, p. 693 S.C.R.). So it can readily refer to a company which is operating at a profit and making a significant return on its investment.

[123] The above shows that even the small degree of retrospectivity permitted by the 1959 and 1977 *Gas Utilities Act* amendments is more limited than it sounds. Rates come into force in the future, and are intended to reflect estimates of **future** costs revenues and conditions when they are in force. The rule against looking at losses (or extra profits) which occurred before the application date is not arbitrary; in part it reflects that rule of future rate-making. Past ongoing expenses can be looked at when predicting future ones, but past unexpected shortfalls (one-time events) in general can never be recovered. I return to the stages of the rate-making process, and some confusion about it in subpart 6 below.

[124] That is orthodox and traditional rate-making law: see 1 Priest, *Principles of Pub. Util. Regulation* 75, including n. 102 (1969); Netz, *loc. cit. supra*. And see subpart 4 below. The legislation confirms that law. What was referred to in the earlier court decisions as s. 31 or s. 32 of the *Gas Utilities Act* is now s. 40. It requires "rates, tolls or charges . . . **to be** imposed, observed and followed **afterwards** by an owner of a gas utility." (emphasis added)

[125] The Supreme Court of Canada's 1979 ***N.W.U.L.*** decision then quoted with approval another decision of this Court also explaining the 1959 amendment to the legislation:

> . . . It was to deal with rates prospectively and having done so, so far as that particular application is concerned, it ceased to have any further control. To give the Board [now the Commission] retrospective control would require clear language and there is here a complete absence of any intention to so empower the Board.
> – ***Calgary (City) v. Madison Nat. Gas Co.*** (1959) 28 W.W.R. 353, 19 D.L.R. (2d) 655, 661 (quoted at end of para. 7 (A.R.) of the Supreme Court of Canada's 1979 ***N.W.U.L.*** decision)

[126] The Supreme Court also quoted with approval another decision of this Court on the unfairness of retroactive rate hikes:

> One effect of this ruling is that future consumers will have to pay for their gas a sum of money which equals that which consumers prior to August 31, 1959 ought to have paid but did not pay for gas they had used. In short, the undercharge to one group of consumers for gas used in the past is to become an overcharge to another group on gas it uses in the future. When the Board capitalized this sum, it made all the future consumers debtors to the company for the total amount of the deficiency, payable ratably with interest from their respective future gas consumption.
> – ***Re N.W.U.L.*** (1961) 34 W.W.R. 241, 25 D.L.R. (2d) 262, 290 (quoted in para. 21 (A.R.) of Supreme Court of Canada's 1979 ***N.W.U.L.*** decision)

[127] That danger is acute here, with 2005 customers asked to pay what 1999 customers consumed but allegedly did not pay. And Calgary has a very mobile population and grew rapidly through the early 2000s.

3. Cost-Plus Billing

[128] If one were to ignore all the law above, in theory gas utilities could instead use a different system. Consumers could pay them for gas on a cost-plus basis. Cost-plus is the way that

government contractors like to be paid, and that law firms often charge. In theory, one could simply set rates for each year after the fact, once all the gas had been consumed, and all the consumption and expense figures were in and verified. In the meantime, consumers would merely pay something on account, and have the actual final figure adjusted later by a refund or extra charge.

[129] Such a full cost-plus system would be novel in public utilities. And probably unworkable if done openly. But, in my view, ATCO's request which the Commission approved here is perilously close to that in all but name. That is not just my speculation. The Commission more or less said so itself, in its 2005 decision (p. 10, A.B. p. F13), and its 2006 decision (p. 2), both quoted in Part E.2 below.

[130] The cost-plus system has dangers. Of course one is the intergenerational expropriation referred to by this Court, and by the Supreme Court of Canada (in its ***N.W.U.L.*** 1979 para. 21 quoted at the end of subpart 2 above).

[131] When I discuss incentives at various places in this judgment, I am not imputing improper motives. A utility company is not a charity, and its directors and officers have a duty to its shareholders to maximize its profits (to the extent that the regulatory bodies and law and honesty permit).

[132] Here is another danger. If the utility ends by making a profit, and there is no automatic adjustment at year end, the utility can hope that no consumer group will make a fuss, and so the company can hang on to the profit. If consumers do apply to the Commission, the utility can suggest that it is too early to tell, and to wait a few years to see if arguable offsetting losses turn up elsewhere. So what revenues to offset against what expenses becomes almost arbitrary. Conversely, if the utility makes a loss at year end, it can apply immediately for an additional payment by consumers. The utility will have recourse to the regulator only when the facts mean that it will win and the consumers will lose. On the evils of changing the rules in mid-game, see MacAvoy and Sidak (2001) 22 Enr. L. Jo. 233, 238. Recall that the Alberta deferred rate account is just a number written in a book. It is not a trust account in a bank, or any other type of segregation of funds; nor is it even funds.

[133] And of course cost-plus billing contains no incentive to be economical. Cf. Netz, *loc. cit. supra*, at 403 ff.

[134] Therefore, routing later claims immediately through an old deferred account to give refunds or extract higher rates, in respect of profits or losses years before, in substance is no fixed rate at all (and so clearly illegal). At best it is simply basing rates to be paid in the future on failure to forecast expenses in past fiscal years. As noted above in Part C.2 and in Part D.2, the legislation forbids that. Section 40 of the current *Gas Utilities Act* (quoted in Part C.2) only lets that process look back to the beginning of the fiscal year in which the rate application was filed. I see no exception there for different accounting methods.

4. Commission Powers are Confined by Legislative Aims

[135] In Parts C and D.2 above, I showed that the Supreme Court of Canada and this Court consistently barred retroactive rate-making in general, and banned increasing present rates to cover a past unexpected shortfall in particular, and showed how the Legislature affirmed that (with only small changes).

[136] The justice, consistency, and policy underlying those legal rules have since been explained by the Supreme Court of Canada. It also shows how to interpret such legislation. Its latest decision on the Alberta régime in general, and gas utilities in particular, is the "***Stores Block***" decision, cited as ***ATCO Gas and Pipelines v. E.U.B.***, 2006 SCC 4, [2006] 1 S.C.R. 140, 344 N.R. 293, 380 A.R. 1. It clearly sets out the Commission's proper approach.

[137] The Supreme Court there says that how much discretion utilities or other regulatory tribunals have varies from board to board, but each board must respect the limits of its jurisdiction, and can only act in areas where the Legislature has given it authority (paras. 2 and 35). Utilities regulators regulate rates to protect consumers from natural monopolies (para. 3).

[138] The Supreme Court of Canada says that though Alberta's *Alberta Energy and Utilities Board Act* and *Public Utilities Board Act* and *Gas Utilities Act* contain seemingly broad powers, that legislation must be interpreted within the entire context of the statutes, which balance need for consumer protection against owners' private property rights. The main function of the Commission is to fix just and reasonable rates, so ensuring dependable supply (paras. 7, 60). Therefore, imprecise undefined wide statutory provisions letting the Commission make any order, or impose any condition necessary in the public interest, do not give an unfettered discretion. They must be limited to the purpose of the legislation and the context of the regulatory scheme and principles generally applicable to regulatory matters (paras. 46, 48, 49, 50, 51, 60, 61, 64, 73-77). The "power to supervise the finances of these companies and their operations, although wide, is in practice incidental to fixing rates" (para. 60).

[139] The Supreme Court then examines the history of the Alberta legislation, which is based on similar American traditional utilities rate-regulation legislation (para. 54). Such "public utilities are very limited in the actions they can take" and the Commission has no "discretion . . . to interfere with ownership rights" (para. 58). The 1995 (temporary) merger of the Public Utilities Commission and the Energy Resources Conservation Board (as the Alberta Energy Utilities Board) did not change that, says the Supreme Court (para. 59).

5. Shareholders' Risk

[140] The law's time restrictions are neither mechanical, nor trivial. They are bound up with who enjoys windfall profits, and who risks losses or low returns on investment. The Supreme Court of Canada begins by describing the rate-making process:

> The [Commission] approves or fixes utility rates which are **estimated** to cover expenses plus yield the utility a fair return or profit. . . . The revenue required to pay all reasonable operating expenses plus provide a fair return to the utility on its rate base is also determined . . . In Phase II rates are set, which, under normal temperature conditions are **expected** to produce the estimates of '**forecast** revenue requirement'. These rates will remain in effect until changed as the result of a further application or complaint or the Board's initiative. Also in Phase II existing interim rates may be confirmed or reduced and if reduced a refund is ordered.
> ("***Stores Block***", 2006 SCC 4, para. 65, quoting the Supreme Court of Canada's 1979 ***N.W.U.L. v. Edm.*** decision, emphasis added)

[141] Then the Supreme Court shows that the object is to leave key risks to the equity holders, the utility shareholders:

> Despite the consideration of utility assets in the rate-setting process, **shareholders are the ones solely affected** when the actual profits or losses of such a sale are realized; the **utility absorbs losses and gains**, increases and decreases in the value of assets, based on economic conditions and occasional unexpected technical difficulties, but continues to provide certainty in service both with regard to price and quality. (*id.* at para. 69, emphasis added)

[142] Therefore, the Commission cannot act retroactively and offload risk onto consumers:

> . . . the Board [now Commission] was in no position to proceed with an implicit refund by allocating to ratepayers the profits from the asset sale because it considered ratepayers had paid excessive rates for services in the past. . . . **The Board was seeking to rectify what it perceived as a historic over-compensation to the utility by the ratepayers. There is no power granted in the various statutes for the Board to execute such a refund in respect of an erroneous perception of past over-compensation. It is well established throughout the various provinces that utilities boards do not have the authority to retroactively change rates** [citing ***N.W.U.L.***, ***Coseka***, and ***Dow*** cases]. But more importantly, it cannot even be

> said that there was over-compensation: the rate-setting process is a speculative procedure in which both the ratepayers and the shareholders jointly carry their share of the risk related to the business of the utility.
>
> (*id.* at para. 71, emphasis added)

[143] Striking for the present appeal is the Supreme Court's discussion shortly before that quotation. It says that the utility is not guaranteed a profit, nor a return on its assets, and is merely given a chance to earn them. The utility company owns the assets, and profits or losses accrue to the company (i.e. shareholders), not to the consumers.

> The disbursement of some portions of the residual amount of net revenue, by after-the-fact reallocation to rate-paying customers, undermines that investment process . . .
>
> (*id.* at para. 67)

The customers have no ownership or equity; only shareholders do:

> Shareholders have and they assume all risks as the residual claimants to the utility's profit. Customers have only 'the risk of a price change resulting from any (authorized) change in the cost of service. This change is determined only periodically in a tariff review by the regulator'. (*id.* at para. 68)

[144] The long history of that policy and system are confirmed by an article (also quoted by the Supreme Court): MacAvoy and Sidak (2001) 22 Enr. L. Jo. 233, 235, 237, 241-42, 243-44, 245-46.

[145] This traditional prospective fixed rate-making provides very healthy incentives for the utility company and its shareholders and management. If the utility company can find ways to hold its expenses below those which were forecast, all the extra profit accrues to the shareholders and cannot later be confiscated. In the long run, that approach will benefit both the shareholders and the consumers. For a useful discussion of incentives, see Kahn, *The Economics of Regulation: Principles and Institutions*, v. 1, pp. 47-54, 101-09 (repr. MIT Press 1998).

[146] Besides incentives, that system also gives fairness to the utility company's shareholders. If applied consistently, it is just for everyone.

[147] Calgary's initial January 21, 2005 argument to the Commission (Tab 47, p. 3), pointed out that ATCO's 2004 error-correction application was in effect a request for a backstop guarantee against unexpected shortfalls in profit, citing previous Commission decisions. The Commission's 2005 decision does not mention that concern. The quotations from the Supreme Court of Canada

above show the fundamental error in the Commission's 2008 decision now under appeal. And it is also virtually cost-plus billing, as noted in subpart D.3 above.

[148] Indeed, the Commission's own 2005 decision (being reconsidered here) admits that ATCO's proposal "replaced a prospective process where accounting errors, such as those that are the subject of the Application, should typically have been absorbed by the utility's shareholder" (p. 11, A.B. p. F14).

6. Stages of a Rate Hearing

[149] The term "retroactive" is misleading or confusing in some respects. It is conceivable that it led to some of the unexplained aspects of the present situation. Compounding the problem is the fact that several different things are involved. So expanding on what the Supreme Court of Canada said in ***Stores Block*** will increase clarity.

[150] I will outline simply the traditional and proper process to set or amend rates for a public gas utility in Alberta. (Legal authorities are found above, especially in Part C.2 and subparts D.2 and 5.)

> Step A: Utility completes fiscal years #1 and 2, and routinely files or publishes its financial results for those years.
>
> Step B: During fiscal year #3, Utility files an application to the Commission to increase its existing rates to consumers.
>
> (1) This application always includes (and must include) an **estimate** of what expenses, taxes and rate base will be during the (current) fiscal year #3, and during (upcoming) fiscal year #4.
>
> (2) If the Utility wishes, it may choose also to show the Commission that in the past, some of its expenses have been higher than had previously been forecast, or that some of its revenues have been lower than had previously been forecast. However, legislation and case law (see Part C above) allow the Commission to rely upon such discrepancies between past estimates and actual figures (revenue or expenses), only for two possible time periods:
>
> (a) the current fiscal year, during which the application was filed (i.e. fiscal year #3);
>
> (b) any period during which the current rate hearing is still going on, or the rate decision is standing reserved

> and not yet decided (i.e. fiscal year #3, and also year #4 up to date of decision).
>
> Step C: In Phase I, the Commission sets its own estimate of the expenses and taxes which the Utility will incur, e.g. in year #4, plus a reasonable rate of return on its investments (rate base) for the foreseeable period after the application date. That is a lump sum of future needed gross revenue per year (or month). Then in Phase II, the Commission estimates future gas consumption, and designs a set of rates which it estimates will produce that lump sum of needed gross revenue.

It will be seen from this outline that all rates are future.

[151] Typically, the word "retroactive" is used in this context to refer to something very specific. That is going outside the time limits in step B(2) above. For example, the Commission cannot set a rate which will yield more than the estimated **future** expense, taxes, and return on investment. It cannot do so even if it is proven that the utility earned much less in year #1 (or earlier) than had been estimated, or than the old rates were designed to cover. That is a past loss and is unrecoverable. Similarly, the Commission cannot set future rates which will yield less than estimated future expenses etc. on the ground that in the past year #1 (or earlier) the utility earned more than had been forecast.

[152] Those forbidden acts would not be "retroactive" (or retrospective) in all the common non-technical senses of the word. The common term "retroactive" is appropriate in two senses only. First, all rates should be for the future and known at the time that the consumer decides to consume some (or more) gas. Rates come into force only on the day they are announced (or a later day). (Interim rates are a partial exception, and ignored above for simplicity.) On any given day, a consumer knows what rates apply.

[153] The second meaning of "retroactive" is that already described above: that deviation between past estimates and past actual performance is no ground to change future rates for a later period.

[154] Therefore, one must not confuse two different topics:

> (1) First topic: whether **future** consumption or expenses will be the same as forecast now;
>
> (2) Second topic: whether **past** expenses were the same as previously forecast some years ago.

The first topic (future uncertainty) is sometimes handled by purchased-gas adjustment clauses or deferred gas accounts for gas (raw material) expenses or allied topics. It is in effect a type of temporary interim rate. But the second topic (past discrepancies from budget) is never legitimately allowed for, so long as it is for a previous fiscal year. *A fortiori*, past accounting errors are even less legitimate a topic for later adjustment of rates (even by later surcharges to consumers or refunds to consumers).

[155] In my respectful view, what the Commission did here (at ATCO's request) is therefore forbidden by binding case law and statute in two respects.

[156] Written argument to the Commission was not exhaustive, and may not have spelled out every implication of these points. Possibly the Commission did not distinguish the "first topic" from the "second topic". Its actual reasons on this topic were not lengthy, but I note two things. In Part B.3(c), I quoted the middle paragraph of the Commission's 2008 reasons ("The provisions of the GUA and PUBA relied on . . ." p. 8, A.B. p. F32.) In the mention of retroactivity, note the phrase there "in the event that the [Commission] intends to approve a tariff effective prior to the date on which the tariff application is made." But no such condition or qualification exists in s. 40 or the case law. The time limit about past under-recoveries applies just as much to rates to come into effect later (as rates almost always do). Parts C and D show that at length. Little in the Commission's 2006 or 2008 reasons reviews or applies the full force of the law recited here in Parts C and D. And the original purpose of the deferred gas accounts (step B(1) above) morphed in 2005 into a repeal of the restrictions in step B(2) above.

7. Interim Rates

[157] For all the reasons above, the only legitimate exception to the bar on retroactivity which I see as even arguable, is interim rates.

[158] An interim order must later be replaced by a final order, and the rate will no longer be open to change. See ***Coseka Res. v. Saratoga*** (1981) 31 A.R. 541 (C.A.), and ***Calgary v. Madison*** (*supra*, Part D.2) at 662-63 (D.L.R.) cited with approval by the Supreme Court of Canada in ***Bell Can. v. R.*** [1989] 1 S.C.R. 1722, 1752h-1754f; and also see p. 17600g-1761a.

[159] ATCO's October 5, 2007 argument (Tab 60, paras. 23-26, p. 9) is about ***N.W.U.L. v. Edmonton*** [1961] S.C.R. 392. But that argument acknowledges that the rates dealt with there which were subject to the "purchased gas adjustment clause" were interim. Note Calgary's reply argument of October 12, 2007 (Tab 65) pp. 6-8.

[160] The term "interim" is ambiguous. But the traditional meaning is just that a full rate hearing would take too long, and the company cannot afford to go on that long under the old rates (especially in inflationary times). So a quick and approximate rate increase is put in, in the expectation these

new rates will soon be replaced by more careful ones. That usefully leads to an overlapping topic, the purpose of deferral accounts.

[161] In Parts D.8 and E below, I show why the rates in question here were not interim, still less permissibly interim.

8. Function of Deferred Accounts

[162] The legitimate use of deferred gas accounts fits best here. I will discuss the history of these particular accounts below in Part E.

[163] Is a deferred account any exception to all the law given above? Only to a very limited degree. If the Commission sets an **interim** rate which must be later adjusted and made final, then everything done in the meantime under that interim rate is tentative. That creates two needs. First, the utility company's accounts must be flagged to show that. Second, it may be informative and useful to keep track of and total any discrepancies building up in the meantime, such as the difference between anticipated gas costs and actual gas costs. There are doubtless several methods which would meet those two needs; one method is a temporary deferred account to be adjusted and closed out when the final rate is set.

[164] Therefore, a legitimate deferred account is a result, not a cause; a mere tool, not an objective. Such an account does not cause or legitimize rate changes any more than fur hats cause or legitimize winter.

[165] It is one thing to create a deferred account at the outset of an **interim** rate, to specify what amounts it is to record during that period, and then at the end to reconcile and clear out the account by the final rate, in the way ordained at the outset.

[166] It is quite another thing to return later to a fixed **final** rate and change it after the fact by ordering premium payments by (or refunds to) consumers, and then to try to justify that by **creating** for the purpose a **new** deferred account, into which sums will be put retroactively and immediately be removed (by the premium or refund). And in substance it would be the same to find an old page still in the ledger, which had been created for a different specific purpose but long since closed out and reconciled, and then use it. In other words, retroactively to put into that page (account) the new sum and immediately take it out. That is wrong in principle and in law. It is just changing a final rate after the fact, even after the consumption. See Calgary's argument to the Commission of January 21, 2005, p. 2 (Commission Record, Tab 47).

[167] Any deferred account which is mere memorandum (calculation) by itself changes nothing, excuses nothing, and is at best a result, not a cause. But if it is regarded as unallocated funds whose later ownership depends on profits or losses, then it likely violates the Court of Appeal and Supreme Court of Canada rulings in ***Stores Block*** and similar decisions (in Parts D.2 and D.5 above). The

refund here to the consumers of the unexpected profits plainly falls within that. And the reverse, recouping unexpected profit shortfalls in the deferred accounts, is an even bigger violation of that case law. So for those reasons, I do not see a deferred account as any licence to violate the usual legal rules barring retroactive rates or use of expense overruns too far back.

[168] What if the utility (with or without the permission of the Commission) were ahead of time to set up an unrestricted all-purpose “deferred account” intended to last indefinitely and to permit any rate to be adjusted later because of old events? In my view, that would be tantamount to a purported repeal of s. 40 and the Supreme Court of Canada decisions. No one but the Legislature has power to do that.

[169] ATCO suggested to the Commission that the 1987-1988 deferred gas accounts were not “closed” but “left open” (para. 28, p. 10, ATCO’s October 5, 2007 argument, Comm. Record, Tab 60). The words “left open” are ambiguous. The account was still there, but the relevant years had been reconciled (cleared out) years ago. See Part E below, and the Appendix to this judgment. So in the meaningful sense, ATCO’s submission was incorrect. It had some accuracy only in an irrelevant sense.

[170] ATCO’s same argument (para. 31, p. 11) said that past rates are not changed by the DGA. In a sense, that is of course so. But it says that “future rates reflect, *inter alia*, prior period adjustments occurring . . . in the setting of future rates.” That is precisely what the *Gas Utilities Act* and Supreme Court of Canada and Court of Appeal decisions all forbid. See Parts C and D.1-8 above.

[171] I stress that using a deferred account is the only real reason which the Commission gave for its 2008 Decision now under appeal.

9. Jurisdiction

[172] First, I put to one side a red herring. In its reasons under appeal, the Commission states (without citing authority) that there are no fixed rules about retroactivity, only discretion. The Commission says that such issues “are not, however, jurisdictional impediments” (second last para., p. 8, A.B. p. F32). That seems to echo part of what ATCO had argued (October 12, 2007 argument, p. 4, para. 8, Record Tab 64).

[173] The Commission’s statement is irrelevant. Errors of law and errors of jurisdiction yield the same result on appeal (if clear and unreasonable). As shown above at great length, retroactivity violates a clear rule of law. This is an appeal, and this Court is not confined to questions of jurisdiction. It has power to reverse decisions of the Commission for errors of law: *Alberta Utilities Commission Act*, 2007, c. A-37.2, s. 29(1).

[174] Now I turn to another topic. I should emphasize that the above portions of my reasons do not find want of jurisdiction or power on the part of the Commission. The preceding parts of my

judgment are not a search for a power. So it cannot be a power which existed somewhere else. My suggestion is not a power, or jurisdiction. Instead, I find a legal statutory prohibition (statutory and judge-made).

[175] That distinction imports two things. The first is that powers are very different from rights, and lack of power (technically called a "disability") is very different from a duty. A prohibition and a lack of power operate in different spheres entirely. A power is the **ability** to affect other people's legal position. A right or duty has to do with what the law **requires** or **forbids**.

[176] One can have a power but be under a legal duty not to use it, or not to use it a certain way. See *Dias on Jurisprudence*, 53-54, 56-57, 64 (4th ed. 1976) or pp. 33-34, 36-38, 43-44 (5th ed. 1985); *Salmond on Jurisprudence* 229-30 (12th ed. 1966). An example is an agent making a contract forbidden by the principal, but within the agent's authority. Another is a divorced spouse who cuts the children out of his will contrary to a contract with his ex-wife. (Of course, we must remember that the Commission is a tribunal, not a litigant.)

[177] The second thing flowing from rights vs. powers in this case is easy to overlook. I find an applicable statutory (and precedential) prohibition, not mere non-existence of a grant of power. In other words, I rely on the presence of an actual thing, not the absence of something. Silence in one place does not contradict an express statutory provision in another (whether the issue is powers or duties).

[178] Probably that is the key point. Existence of even one relevant statutory grant of power **upholds** a positive power; even one statutory provision **prevents** legal action if the statutory provision is a negative prohibition. So if the issue were whether a tribunal or person had **power** to do something, only one source of the power would be necessary, and would suffice. That the power came only from one source or location, would be irrelevant; one source or many would make no difference. If instead the issue is whether there is a statutory **prohibition**, then again it need only be found in one place. Even one such statutory provision means that the tribunal or person has **no** right, and the law forbids it to act. And the provisions on which I rely bar rates based on past losses or optimistic forecasts, not approve it.

[179] But there is one difference between the two situations. A statutory grant of power permits effective action; a restriction makes action illegal.

[180] An appeal from a tribunal's act will succeed if the tribunal lacked power, **or** if it contravened a statutory or judge-made legal prohibition, **or** both. So a tribunal acting within jurisdiction and with power, must be reversed if it violated a rule of law. The Court of Appeal must quash it.

[181] Here the Commission had and has **power** to regulate rates, to enter into a hearing of some sort, to prescribe accounting methods, and to grant a wide variety of remedies. The remedies which the Committee granted here were familiar and within its **powers**. None of that is the issue.

[182] The whole issue is what legal rules that hearing was to follow, what considerations or facts were relevant or irrelevant, times for acting, and the limits on reversing earlier decisions. Violation of those legal rules likely produced no nullity. But such violation is illegality, and permits, indeed mandates, appellate reversal.

10. Conclusion

[183] This charge to the southern customers to reimburse ATCO for its various accounting deficiencies is illegal retroactive rate-making for ten reasons.

(a) It is all based on events long before the beginning of the fiscal year of the application, indeed totally outside any rate application. That contravenes all the law set out in Part C (history) and in subparts D.2 to D.6 above. If the adjustment application is even a rate application, it is a May 2004 application, but the adjustments go back to 1998 or 1999.

(b) The rates were final years ago, at the latest when the DGAs were reconciled monthly.

(c) The DGAs themselves were thus reconciled years before.

(d) The DGAs were never intended nor ordered to be used for this purpose. See Part D.8 above, and Part E below.

(e) ATCO's and even the Commission's reasoning would imply that the existence of this one continuous deferred account going back to 1987 or 1988 would leave open all future gas rates back to those years! That would be absurd.

(f) This is just errors from lax accounting, discovered belatedly.

(g) The Commission never even discussed the implications of the fact that on its own fact statements, this is basically cost-plus charges, not fixing rates. The essence of that is at best retroactive rates, at worst no rates at all. See Parts D.2, D.3, and D.5.

(h) The Commission shuffles the risk of shortfalls in profit onto the consumers (or rather different later consumers). See Parts D.3 and D.5.

(i) The Commission's reasons seem to contain errors on their face. See the end of Part D.6.

(j) This is clear and unreasonable error of law. See Part D.9.

E. History of Deferred Gas Accounts

1. Introduction

[184] Since the Commission later saw deferred accounts as a way to bypass the retroactivity rule, the nature and history of the accounts in question here is important.

[185] These accounts are so old that they were set up 22 years ago for different companies which once had the gas franchises which ATCO now enjoys.

2. Creation and Purpose

[186] I quote the Commission's own history of these accounts, to show that they were never intended for the present purposes, and had long since been reconciled (cleared out) for the years in question.

> DGA [deferred gas account] procedures were initially approved by the Board [now Commission] in 1987 and finally approved in 1988 **for the purpose of reconciling actual costs of gas incurred by a utility with forecasts that it used in setting a GCRR [Gas Cost Recovery Rate], i.e. the rate it used to recover the commodity costs of gas from sales customers**. These procedures ensured that customers paid only the actual cost of gas consumed by them. In addition, they ensured that the utility neither profited from nor suffered losses in the course of selling the gas. This premise currently remains in effect for the sale of gas under a regulated rate.
>
> **Initially, reconciliation of the DGA was made on a winter and summer seasonal basis** when the application for the respective period's GCRR was filed. **In 2001, the Board approved a change in the methodology for determination of a GCRR from a seasonal to a monthly basis**. This change in methodology was implemented in April 2002. The purpose of allowing prior period adjustments in the DGA was to allow for forecasting inaccuracies, relative to the timing of actual gas acquisition costs incurred, that would have otherwise impacted the determination of a GCRR.
>
> (2005 decision at p. 8, A.B. p. F11, emphasis added)

* * *

The Board concluded from this prior decision that the DGA was not intended to be a permanent fixture, but was expected to be in place until the volatility of gas prices had decreased to a point where AG could revert to its previous practice of forecasting the gas costs on a prospective basis. The difference between the two practices was that prior to the implementation of the DGA, any difference between forecast and actual was to the account of the shareholder, whereas in the DGA process the differences fell to the account of the customer.

It is clear to the Board that the only purpose of the DGA was to provide a method of correcting the customer rates due to the volatility in the purchase price of natural gas.

(2005 decision at p. 10, A.B. p. F13)

* * *

. . . the Board must remain mindful of the essential nature of the DGA as a deferral account and the allowances in the past of certain prior period adjustments spanning a number of years.

(2005 decision at p. 11, A.B. p. F14)

* * *

Decision E88018, dated March 18, 1988 stated:

> **The DGA procedure was proposed [by AG's predecessors] to be in place until gas costs could be forecast with a reasonable degree of certainty**.

and in a later section also stated:

> [AG's predecessor] contended that once gas prices attain some stability and can be forecast with some degree of accuracy, there likely will be no need for a DGA type account. If a DGA mechanism is not approved, [the predecessor] suggested that there would be significant swings to its earnings. [The predecessor] confirmed that when the first reconciliation proceedings are held, the Board and the Intervenors may examine not only the projected gas costs for the next reconciliation period but also those costs that are related to the period under review. (Tr. p. 488) And further:
>
>> 'There's no attempt in the deferred gas account mechanism that's been proposed to bypass the

> Board's ability to rule on the prudence of a cost.' (Tr. p. 489)

The Board concludes from this prior decision that **the DGA was not intended to be a permanent fixture, but was expected to be in place until the volatility of gas prices had decreased** to a point where AG could revert to its previous practice of forecasting the gas costs on a prospective basis. The difference between the two practices was that prior to the implementation of the DGA, any difference between forecast and actual was to the account of the shareholder, whereas **in the DGA process the differences fell to the account of the customer**.

It is clear to the Board that the only purpose of the DGA was to provide a method of correcting the customer rates due to the volatility in the purchase price of natural gas.
(*id.* at pp. 9-10, A.B. F12-13, emphasis added, footnotes omitted)

*** * ***

In some cases, . . . prior period adjustments have been specifically approved for imbalances resulting from measurement errors that have related to periods of over one year.
(2005 decision at pp. 10-11, F13-14)

* * *

Previous to the establishment of the DGAs, a utility treated all estimates for its gas supply, both volume and price, as prospective in its General Rate Application (GRA). The establishment of the DGA provided a means by which a utility could make corrections and adjust for the actual price of the gas supplied and thereby correct the customer rates. The regulated sales rate used to recover the cost of gas was called the gas cost recovery rate (GCRR). Use of the DGA takes into account that, under a regulated gas sales rate, customers pay only the actual costs of the gas consumed by them and **the utility is neither to incur a profit nor suffer a loss** in the course of procuring and selling the gas.

> **In 1987 parties believed that the DGA would be a temporary feature because the continuing volatility of gas prices was not anticipated**. However, contrary to these expectations, the purpose and need for the use of DGAs has continued. Initially, the DGAs were reconciled twice a year on a winter/summer seasonal basis. During the period from 1987 to March 2002, the Board allowed prior seasonal adjustments to be made in reconciliation of the DGA in respect of the preceding same season.
>
> (2006 decision, p. 2, emphasis added, footnote omitted)

[187] More examples are found in the Appendix.

3. Loose Later Practices

[188] However, ATCO's practices later became lax in a number of respects, and sometimes small adjustments of other types were made in the deferral accounts. That had never been the purpose of the accounts. The Commission described that:

> . . . However, the Board [now Commission] is aware that, during the approximate 16 years that the DGA has been in place, it has been used to update adjusted imbalance amounts from shippers, producers and interconnecting pipelines. Prior period adjustments for various types of corrections have been relatively common occurrences. While the Board and interested parties may not have previously taken issue with these types of corrections, the Board is concerned that the DGA seems to have evolved into a vehicle to fix all possible errors as a cost of gas to be charged to sales customers under a regulated rate.
>
> (2005 decision at p. 10, F13)
>
> * * *
>
> . . . **The Board believes that, normally, reconciliations were not expected to look back further than 12 months.** As the process evolved, some prior period adjustments were made which extended back further than 12 months. Under special circumstances, for example, involving measuring equipment malfunctions, prior period adjustments involving longer periods have been accepted by the Board. However, the Board considers that **the DGA was never set up with the intention of permitting all prior period accounting errors**, particularly those that would have been subject to ATCO's management and control, **to be processed and rectified through the DGA.**

> **The Board is troubled by the evolutional use of the DGA. The DGA replaced a prospective process where accounting errors, such as those that are the subject of the Application, should typically have been absorbed by the utility's shareholder.** It now appears that the DGA is being treated as a catch-all for fixing errors, including those that have a long history, or appear to be the result of human error, where adequate processes have not been in place to capture and correct the problem at an early stage. Notwithstanding that some prior period adjustments previously approved by the Board may have covered an extended period of time, the Board considers that **seven years represents a significant lag presenting obvious intergenerational equity issues.**
>
> (*id.* at p. 11, F14, emphasis added)

4. Calgary's Argument

[189] Calgary's factum and book of authorities cite or quote past Commission orders fully confirming the Commission's recitals quoted above (in subparts 2, 3). The appellant also shows that those accounts were promptly reconciled to allow for errors in prediction, and that the Commission gave orders replacing the interim rates initially established with final rates reflecting the reconciliations. After some years, that was done monthly (based on a three-month rolling average).

[190] In written argument filed with the Commission on its 2008 application, ATCO had objected that the Commission should not see a full history of its own orders governing the deferred gas account. That objection is hard to reconcile with the arguments which ATCO had made to the Court of Appeal in the 2007 appeal (need for a fuller record). However, ATCO did not object to that evidence in this new appeal. (ATCO's original argument to the Commission that ATCO lacked time to check old Commission decisions was not made again to the Court of Appeal, and of course became moot long ago.)

[191] Old Commission decisions are not exactly evidence (not really fact) and are not much (if at all) law. They are previous process, and are all about the same utility (or its two predecessors). They are not tendered here to prove facts, but for their directions and decisions.

[192] In the present appeal, the appellant Calgary, the respondent ATCO, and the Commission itself, all reproduced old Commission decisions in their various books of authorities.

[193] Any court can look at its own previous decisions and records. See ***Kin Franchising v. Donco*** (1993) 7 Alta. L.R. (3d) 313, 316 (para. 7) (C.A.); *Alberta Evidence Act*, R.S.A. 2000, c. A-18, s. 42. Additional authorities are found in 3 Stevenson & Côté, *Civil Procedure Encyclopedia*, p. 45-54 (ch. 45, Pt. Z.3) (2003). I see no reason to withhold that power from a formal tribunal like this Commission (with all its powers). See the *Alberta Utilities Commission Act***,** 2007, c. A-37.2, s. 11,

and cf. ***Germain v. Auto Injury App. Comm.***, 2009 SKQB 106, [2009] 7 W.W.R. 509. Especially when the tribunal is an ongoing regulator with constant applications over the rates and accounts of the same handful of companies. This Commission has looked at its previous decisions for many many years. A classic decision of the Supreme Court of Canada says that the Commission can get its information in whatever mode it sees fit: ***N.W.U.L. v. Edmonton*** [1929] S.C.R. 186, 193. And if the Commission can take notice, why cannot the Court of Appeal take such judicial notice on appeal from the Commission?

[194] Furthermore, it was ATCO itself which began all this, and its application to that end expressly submitted that the Commission should make the "adjustments" (surcharges) to consumers by looking back to the Commission's old approval of DGAs. (See ATCO's application of May 31, 2004, § 4.1 "History", present Commission Record Tab 1, pp. 4-5.)

[195] Therefore, it is not surprising that the Commission did **not** decline to look at any previous decisions by itself. Instead it recited and quoted a number of them in its 2005 original decision, and in its 2008 decision reconsidering that. The Commission did **not** say (in 2005 or 2008) that it (or Calgary) lacked evidence about this.

[196] The Commission's public website gives ready access to some decisions from 1996 to 1999, and many thereafter. Quicklaw also reports its decisions from 2002. Print copies of all Commission decisions (to 1999) are available in one Law Society Library and (to 2008) in the Alberta Government Library. (The University of Alberta law library has some Commission decisions.) The Commission will supply copies on request. So the text of past decisions is not open to doubt. Anyone can access them to check the accuracy of quotations or summaries.

[197] Therefore, the Commission was correct to inspect its past decisions on DGAs. I have amplified my recitals of this history by quoting two or three additional passages from old Commission decisions (pointed out by ATCO in its October 12, 2007 argument, Tab 64, p. 3, quoting decision 2005-036). I have also described some additional passages from Calgary's argument of October 5, 2007 to the Commission (Tab 61): see an Appendix to this judgment. The description has been checked against the original Commission decisions.

[198] In any event, the old controversy about taking notice of the former Commission orders has no effect on the result, because those additional references to past orders reinforce but do not change the factual picture painted by the Commission itself in the 2008 decision now under appeal.

F. The *Bell Telephone* Decision of the Supreme Court of Canada

1. Introduction

[199] Counsel cited ***Bell Canada v. C.R.T.C. (Bell Aliant)***, 2009 SCC 40, [2009] 2 S.C.R. 764. It involved telephone companies' infrastructure under federal legislation.

2. Legislation

[200] The Canadian Radio-television and Telecommunications Commission no longer regulates telephones under traditional rate-regulating legislation. Now it must follow Canada's *Telecommunications Act*, 1993 c. 38, whose objectives, duties, and powers are vastly broader, and cover more than telephones.

[201] I will outline some features of the *Telecommunications Act*, which have no equivalent in Alberta's 1999-2007 legislation applicable to gas utilities or their rates (the *Alberta Energy and Utilities Board Act*, the *Gas Utilities Act*, and the *Public Utilities Act*.)

[202] The *Telecommunications Act* imposes on the C.R.T.C. a mandatory duty to implement a number of very wide and deep policy objectives when it exercises any of its powers or performs any of its duties (s. 47(a)). Among those mandatory objectives are to

– safeguard, enrich and strengthen the social and economic fabric of Canada . . . (s. 7(a))

– enhance . . . efficiency and competitiveness, at the national and international levels . . . (s. 7(c))

– promote . . . ownership and control . . . by Canadians. (s. 7(d))

– promote the use of Canadian transmission facilities . . . within Canada . . . and points outside . . . (s. 7(e))

– foster increased reliance on market forces . . . (s. 7(f))

– stimulate research and development . . . and encourage innovation . . . (s. 7(g))

– respond to the economic and social requirements of users . . . (s. 7(h))

– contribute to the protection of . . . privacy (s. 7(i))

[203] The C.R.T.C. also has unusual statutory powers. It can require any telecommunications company to provide any service in any manner (s. 35(1)) or to construct any facility (s. 42(1)). And (most apposite here), the Commission can require the company to "contribute . . . to a fund to support continuing access by Canadians." (s. 46.5(1)). Therefore the C.R.T.C. has positive proactive

duties going far beyond fair prices (rates), reliability of service and supply, or even safety, of one company.

3. The Supreme Court's Decision

[204] The Supreme Court of Canada (and the Federal Court of Appeal) confirmed the C.R.T.C.'s decision to follow a scheme which it ordered a few years before. That was not to reduce excessive phone rates (for competition reasons), but instead to hold a portion of the revenue in profitable urban markets in a special account to be later spent on infrastructure improvements to benefit consumers.

4. Is the Supreme Court of Canada Decision Distinguishable?

[205] I have concluded that the ***Bell*** decision can and should be distinguished here, for the following eight reasons.

(a) Different Legislative Objectives and Powers and History

[206] The Supreme Court of Canada itself expressly distinguished Alberta's *Gas Utilities Act* and said that the federal C.R.T.C. has broader objectives and power than does Alberta's Commission. See the ***Bell*** case, paras. 17, 22, 36, 39-43, 45-48, 50-53, 55, 57, 72, 74-75 and 77. The Supreme Court of Canada even distinguishes decisions about the C.R.T.C. in earlier years when that tribunal was governed by the more traditional type of rate-of-return regulation like the Alberta system. (In those days the old system was mandated for telephone companies by the *Railway Act*.) See the ***Bell*** decision at paras. 39-46, and 62. See subpart 2 above. To the same effect is para. 41 of the Federal Court of Appeal decision (2008 FCA 91) which the Supreme Court of Canada affirmed.

[207] In particular, the Supreme Court of Canada pointed out that traditional rate regulation is a two-way contest between the interests of the utility company and its particular consumers. The C.R.T.C. (on the other hand) has to meet objectives for all Canadians in all parts of Canada, e.g. fostering competition: see paras. 45 and 47. What is in issue in the present dispute between Calgary and ATCO is the limited traditional type of rate-making power. See the precise passages in Court of Appeal and Supreme Court of Canada decisions, describing and mandating that Alberta scheme, quoted in Parts C and D above.

[208] The present ATCO appeal is about a price (rate or revenue) fair as between the utility and the consumer; nothing more. Though the ***Bell*** decision's origin had a little to do with such questions, the actual ***Bell*** decision was about increasing access and competition, and dictating to the various telephone companies compulsory long-term infrastructure competition.

[209] See also subpart (b) below, on "price-cap regulation".

[210] There is an even more striking distinction between the C.R.T.C. and Alberta's Commission. For most of its history, the Commission has been separate from the Energy Resources Conservation Board. The rate regulator, the Alberta Utilities Commission, is now again separate. The broader policy about the industry and its physical form is no part of the Commission's functions, as illustrated by the Genesee power plant decision: ***Alberta Power v. Public Utilities Bd.*** (1990) 102 A.R. 353 (C.A.). Though the Energy Resources Conservation Board had decided that the new second Genesee power plant was needed and gave a permit to build it, after the plant was built, the Public Utilities Board (now the Commission) could and properly did exclude it from the rate base as not "used or required to be used".

[211] Alberta's two tribunals were temporarily merged effective February 15, 1995 (by 1994 c. A-19.5). But the merger ended effective January 1, 2008 (by 2007 c. A-37.2), before the decision under appeal. Furthermore, the **legislation** for the two tribunals remained separate even during the period of the merged tribunal, 1995-2007.

[212] See also ***Barrie Pub. Utils. v. Cdn. Cable TV Assn.***, 2003 SCC 28, [2003] 1 S.C.R. 476, 225 D.L.R. (4th) 206 (paras. 9-19).

(b) Different Purposes for Setting Up Deferred Accounts

[213] I must stress that in ***Bell***, the C.R.T.C. was using an entirely new type of utility regulation (invented in the United Kingdom in the 1980s). It is called price-cap regulation. Unlike traditional rate (price) regulation, this does **not** fix rates; in order to give incentives, it merely sets a maximum and makes sophisticated allowances for the result. The difference between the two types of regulation is explained by Netz, *loc. cit. supra*, at 417 ff., especially p. 425-28.

[214] One cannot just look at the title of an account, or fixate upon a name like "deferred". One must find the purpose and operation of the account in question. See Part D.8 above.

[215] From the outset, the account described in the ***Bell*** decision was designated expressly to decide later who would own or use the money contained in it. See the Supreme Court of Canada decision, paras. 6, 8-9, 22 (and the Federal Court of Appeal's paras. 43 and 52.) That surplus sum was expected to arise, and did arise, from continuing to charge high urban rates, despite a new theoretical or tentative cap on rates. The difference (surplus) was to be collected and held in the new fund (account) (para. 6). That was a scheme very different from the Alberta fixed-rate scheme. Too many such statements in the Supreme Court's ***Bell*** decision emphasize the fund's very different purpose to list them fully; some are found in its paras. 37, 57, 61, 63, 64, 66, and 67.

[216] The Alberta accounts (DGAs) had very different purposes. They came from an old short-term system for handling very unpredictable raw material costs (gas field prices). It seems to have been an accident, oversight or happenstance (not a Commission order) that they lasted for years. See the detailed history above in Part E.

(c) Alberta Balance Was Largely the Product of a Single "Adjustment" Entered After the Fact Years Later, not an Ongoing Thing

[217] Alberta's deferral account had already been reconciled years earlier, i.e. settled. I doubt that it still "existed" in any real sense in 2004, still less that the 1998 or 1999 parts did. Revisiting the old Alberta deferral account was just a device invented years later when a long-standing and ongoing error was finally discovered: see Parts B.1, 2 and 3(a), and D.3 and D.8 above. Here the Commission let the utility use an old account which had been set up for one temporary purpose to be used for a totally different purpose than that contemplated before.

[218] Conversely, in the ***Bell*** case, the C.R.T.C. managed an existing fund of money growing steadily. The C.R.T.C. largely and in principle confirmed its original purpose.

(d) Encumbered Fund vs. Deficit

[219] The ***Bell*** judgment and C.R.T.C. order were a final decision about ownership of surplus funds which previously had encumbered or provisional ownership. See the Supreme Court of Canada decision, paras. 63, 65.

[220] However, ATCO's account was on balance (and entirely in the south) a deficit, not a surplus. A deficit cannot have an owner, nor be encumbered. Still less was any deficit intended or ordered to have either here.

(e) Limited Term in *Bell*

[221] The ***Bell*** account had a definite beginning and end, forecast at the outset (2001-7 but later ended early, in 2006). See the Supreme Court of Canada decision, para. 9, cf. paras. 10-13.

[222] In ***Bell***, the rates were confirmed and adjusted once and for all, to prevent any further accumulations of reserve funds. The fund (account) was to be closed out and cease to exist: see the Supreme Court of Canada decision, paras. 13 and 15 end.

[223] But the Alberta Commission's 2005, 2006, and 2008 decisions allowed the old gas companies' deferred accounts to be available in future to do it all again (though usually not beyond two years). See Part B.3 above.

(f) The *Bell* Rates Were in Effect Interim, Whereas ATCO's were Final

[224] This is stated by the Federal Court of Appeal's decision, paras. 50-52, and by the Supreme Court of Canada's decision, para. 61.

(g) *Bell* was Confined to Certain Geographic Areas

[225] The funds in the telephone companies' deferred accounts were confined to excess revenue in geographic areas where more competition was needed. Structural changes were needed and so the C.R.T.C. authorized them. Those areas were residential local services in non-high-cost serving areas basket (mostly urban): see ***Bell*** paras. 4, 6, 10. But in the present ATCO appeal, all (later) gas customers simply got a retroactive rate increase (or refund).

(h) *Bell* Refunds were Incidental

[226] In principle, the C.R.T.C. ordered the telephone companies to spend all the reserved segregated funds on service improvements (handicapped services and more broad-band capacity). Refunds to customers were just incidental amounts which could not be spent: see the Supreme Court of Canada's decision, paras. 14, 15, and 20.

[227] But the only use or remedy even suggested before Alberta's rate-making Commission was a second charge (or refund) to the customers for the same old gas long since consumed.

G. Other Distinguishable Decisions

[228] The Commission's decision and some factums cited ***Epcor Generation v. A.E.U.B.***, 2003 ABCA 374, 346 A.R. 281 (one J.A.). Note that a power to change rates retroactively there was conceded; here it is in issue. The rate was agreed there to be interim (paras. 12, 14, 15), not final as here. Calgary's argument to the Commission in the present case (October 12, 2007, Tab 65, p. 2) quotes statements by the Commission in ***Epcor*** confirming that. The proposed dispute on which leave was sought was only over details, indeed unique sharing ratios (***Epcor***, para. 13), not retroactivity itself as here (paras. 9-10). That motion dealt with a defined time and topic only: the 2000 pool price of electricity. And many issues were factual (paras. 23 ff.). It was a decision by only one Justice of Appeal on a motion for leave, not an appeal. ***Epcor*** is not on point.

[229] One other case cited is ***Re Board of Commissioners of Public Utilities (Ref. re s. 101 Public Utilities Act)*** (1998) 164 N. & P.E.I.R. 60 (Nfld. C.A.). This was a split decision. It involved Newfoundland legislation on regulation of electric utilities. Except for the broad outlines, that legislation bears no resemblance to Alberta legislation regulating gas activity rates.

[230] The majority of the Newfoundland Court of Appeal held that setting a rate of return for a utility was not just a step in calculations leading to fixing rates (prices). They held that it set a ceiling for rate of return, and if the later actual rate of return exceeded that ceiling, the Commission could later adjust rates to offset that. Such a rate-of-return ceiling enforced later is emphatically not the Alberta practice or legislation. Nor can I reconcile that view with the Supreme Court of Canada's later decision in the ***Stores Block*** case, *supra*. Indeed the Newfoundland Court of Appeal largely proceeded on its own interpretation of its legislation, and scarcely mentioned any of the Supreme

Court of Canada decisions cited above (and none of the Alberta Court of Appeal decisions). I do not find the majority decision persuasive. It is distinguishable, in any event.

H. Standard of Review

1. Conflicting Precedents on This

[231] First, the Supreme Court of Canada held that the standard of review was correctness: ***Barrie Pub. Utils. v. Cdn. Cable TV Assn.***, 2003 SCC 28, [2003] 1 S.C.R. 476, 225 D.L.R. (4th) 206 (paras. 9-19). Then it gave a somewhat different decision, as follows. Whether the Commission has a given power is determined on appeal on the standard of correctness, but if it is found to have that power, the actual method used to carry out the power attracts a more deferential approach: "***Stores Block***" case, ***ATCO Gas and Pipelines v. E.U.B.***, 2006 SCC 4, [2006] 1 S.C.R. 140, 344 N.R. 293, 380 A.R. 1.

[232] I am reluctant to try to create my own ***Pushpanathan*** analysis here, and then use it to decide which Supreme Court of Canada decision to follow, or to try to distinguish one of the Supreme Court of Canada decisions.

2. Standard Does Not Matter Here

[233] Nor need I do so here, for it would not affect the result. Even on the reasonableness tests, the decision of the Commission under appeal is unreasonable and does not survive. That is so for the reasons given in Part D.10 ("Conclusion") and Part F above. None of those topics is discretionary. The legal limits here are statutory or based on binding precedent, and go to the very nature of the process. The errors are fundamental, and ones of basic principle. Parts D.4, D.5 and D.6 show that. The Commission cannot be acting reasonably when it departs from the fundamental principles laid down by the Legislature and the courts for the Commission to follow. It did depart seriously here, and its decision is unreasonable. See also Part D.9 above.

I. Conclusion

[234] It is now about 12 years since the accounting errors in question began, and about six years since ATCO sought relief from the Commission. The Commission has held three hearings on the topic and has declined to hear more evidence. I would fear denying justice by delaying justice, were we merely to tell the Commission to reconsider the topic in yet a fourth hearing.

[235] I would have allowed the appeal, and vacated so much of the Commission's 2005 and 2008 orders as allows the (southern) recovery of former costs or expenses. I would have directed the Commission under the *Alberta Utilities Commission Act* s. 29(14), that the law requires it to dismiss that part of ATCO's application entirely. There was no appeal, nor leave to appeal from the (northern) rebate to consumers.

[236] I would have awarded costs of the appeal to the City appellant payable by ATCO. There should be no costs to or from the Commission, even though its factum went rather far into the merits. But I would caution the Commission that doing that endangers its position in various respects. See ***N.W.U.L. v. Edmonton*** [1979] 1 S.C.R. 684, 708-09, paras. 36-37.

J. Procedure

[237] The appeal book contains a fuzzy scan of the three Commission decisions in question, and of some court orders. In future, documents should either be printed from electronic copies, or sharp photostats should be made from originals. In contrast, the Commission's filed record has perfect clarity.

[238] The Commission filed one copy of its record, as directed by s. 29(10) of the *Alberta Utilities Commission Act*. Rule 537.1 then contemplates that counsel for the appellant will file multiple copies of Extracts of Key Evidence to supplement the Appeal Digest, reproducing only those parts of the full record that are needed (by all parties) to dispose of the appeal. If the appellant overlooks including something, the respondent can also file Extracts of Key Evidence. No party filed any extracts here. A panel contains three justices, usually based in two different cities, so the absence of individual sets of Extracts hinders the efficient disposition of the appeal.

[239] The appellant's citations of court cases included no reported citation. That violates the Consolidated Practice Directions, para. D.1(b). In future it would help this Court to have at least one publisher's (or website) citation (as well as the neutral cite).

Appeal heard on January 13, 2010

Reasons filed at Calgary, Alberta
this 23rd day of April, 2010

Côté J.A.

Appearances:

B.J. Meronek, Q.C.
for the Appellant (Applicant) City of Calgary

J.P. Mousseau
P. Khan
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L.A. Goldbach
for the Respondent (Respondent) ATCO Gas and Pipelines Ltd.

Appendix

More History of Deferred Gas Accounts

N.W.U.L. = Northwestern Utilities
C.W.N.G. = Canadian Western Natural Gas

1987	Orders E87051 and E87052 (July 3): Commission approved in principle applications by ATCO's predecessors to establish a Deferred Gas Accounting and Reconciliation procedures, to be in place until cost of buying gas could be forecast with reasonable certainty.
1988	Decision E88018 and Order E88019 (March 18): Commission held (on N.W.U.L. and C.W.N.G. rates) that the Gas Cost Recovery Rate was interim and would change at least two times/year. Seasonal rates were to be established, but the Commission would monitor the reconciliations more frequently: monthly. The actual review and finalization would be done two times each year. The cumulative actual balance in the DGA on each March 31 and each October 31 would be refunded to or collected from customers through the GCRRs in the ensuing season. Thereafter in 1988 further Commission orders did reconcile those accounts two times/year for each gas company.
1989-1991	Further Commission orders also in effect reconciled the accounts. Decision C90041 (December 7, 1990) confirmed the system. Some of these orders said that the rates remained subject to review. Interim Order E89020 (April 4, 1989) said that DGA balances should be minimized, and so any significant increase in gas supply costs between normal application dates should lead to an application by C.W.N.G. for a change in the GCRR.
1994-1997	By Decision 94072 (October 28, 1994) DGA reconciliations for C.W.N.G. were to be annual, not semi-annual. GCRRs were from time to time approved. Order U97010 (January 16, 1997) quoted and reiterated Order 89020 (of April 4, 1989), which in turn summarized Order 88018. Order U97052 (May 7, 1997) re C.W.N.G. said that the DRA calculation method meant that under- or over-recovery in one-half year cumulated in the DGR would be collected or refunded in the next one-half year's period, given normal weather and accuracy of sales forecasts. This would substantially maintain intergenerational equity. Order U97053 (May 7, 1997) for N.W.U.L. gave final approval of the company's GCRR for 2-1/2 months.

	Decisions U97129 and U97130 (October 31, 1997): Commission reconciled C.W.N.G.'s and N.W.U.L.'s actual gas cost recoveries.
1998	Decision U98067 (April 13) accepted C.W.N.G.'s reconciliation and refused requests to re-examine the DGA process. Order U98071 (May 4) confirmed C.W.N.G.'s summer GCRR as final.
1999-2000	Various interim orders. Order U2000-161 (April 17) made ATCO Gas-South's GCRR final. More interim orders made for both companies. Order U2000-308 (October 27) deferred acceptance of ATCO North's (former N.W.U.L.'s) reconciliation and set a new interim rate.
2001	Order U2001-001 (January 24) left GCRR rates for ATCO South as interim. Order U2001-002 (January 24) was similar for ATCO North. Order U2001-061 (March 28) was similar; as were Orders 2001-062 (March 28) and U2001-448 (December 14).
	In 2001 the Commission held a hearing re methods to set the GCRR. Decision 2001-075 (October 30) (on methodology) described the existing procedures (reconciliation two times/year) (pp. 3-4), but noted the DGA balances had become large. The Commission decided (p. 64) to switch to monthly written reconciliations to minimize DGA balances. A three-month rolling period would be used for reconciliations.
2002	Decision 2002-026 (April 18) (p. 3) recited the Commission's duty and power to fix "the appropriate final share of the deferral account balances due from each customer class". On p. 4 the Commission said it had been hoped under- and over- recoveries in the DGA would balance out but unexpectedly they had not. But in principle, rates should be established prospectively.
2003	Decision 2003-106 (December 18) (p. 135) said that for the DGA and reconciliation the GCFR would be revised monthly.

5

COURT OF APPEAL FOR ONTARIO

CITATION: Union Gas Limited v. Ontario Energy Board, 2015 ONCA 453
DATE: 20150622
DOCKET: C58756

Hoy A.C.J.O., and Simmons and Tulloch JJ.A.

BETWEEN

Union Gas Limited

Appellant

and

Ontario Energy Board

Respondent

Patricia D.S. Jackson, Crawford Smith and Alex Smith, for the appellant

Michael Millar, for the respondent

Heard: December 16, 2014

On appeal from the order of the Divisional Court (Justices Colin D.A. McKinnon and Susan G. Himel, Justice Herman J. Wilton-Siegel dissenting) dated December 20, 2013, with reasons reported at 2013 ONSC 7048, 316 O.A.C. 218, affirming the decision of the Ontario Energy Board, dated November 19, 2012.

Simmons J.A.:

A. INTRODUCTION

[1] Union Gas Limited appeals with leave from an order of the Divisional Court dismissing Union's appeal from a decision of the Ontario Energy Board. The

main issue on appeal is whether the Board's decision contravened the principle against retroactive ratemaking.

[2] In April 2012, Union applied to the Board for an order amending the rates it would charge to its customers for natural gas as of October 2012. A primary purpose of the application was to adjust rates as a result of allocating a portion of Union's 2011 utility earnings between Union and its ratepayers under the terms of an Earnings Sharing Mechanism ("ESM") contained in an Incentive Regulation Mechanism Settlement Agreement (the "IRM Agreement").

[3] In 2007, Union entered into the IRM Agreement with parties representing its major stakeholders and constituents (the "interveners") to provide for a five-year period of incentive regulation. By order made in January 2008, the Board approved the IRM Agreement. The IRM Agreement contained the ESM, under which Union agreed to share utility earnings greater than two per cent above its regulated rate of return with ratepayers.

[4] As part of the IRM Agreement, Union agreed to reduce its revenue requirement by $4.3 million. In exchange for this reduction, four deferral accounts previously established by the Board were eliminated.

[5] Deferral accounts allow a regulator to separately accumulate certain amounts (costs or revenues) before deciding by order, at specified intervals, to what extent, if at all, such costs or revenues will be charged to ratepayers as part

of rates. Because it is contemplated from the outset that amounts in deferral accounts will be disposed of in a manner that affects rates, deferral accounts do not offend the principle against retroactive ratemaking.

[6] At least one of the four eliminated deferral accounts tracked upstream transportation optimization revenues. Union generated upstream transportation optimization revenues through transactions with third parties in which Union disposed of upstream transportation services.

[7] In the past, the Board had directed that Union share the upstream transportation optimization revenues in the eliminated deferral accounts with ratepayers based on a 75/25 split in favour of ratepayers.

[8] As a result of the elimination of the four deferral accounts, under the IRM Agreement, Union was able to keep net revenues that would previously have been recorded in those accounts, subject to the ESM.

[9] Union's April 2012 application for a rate order included a request to share with ratepayers $22 million in 2011 revenues Union had earned using TransCanada Pipelines Limited's ("TCPL") Firm Transportation Risk Alleviation Mechanism ("FT-RAM") program under the ESM.

[10] Under the FT-RAM program, utilities earned credits for unused firm[1] transportation services, which the utilities could then use to purchase cheaper interruptible transportation services. Union was able to monetize the credits it earned under the FT-RAM program through various assignment and exchange transactions with third parties.

[11] Union classified its 2011 FT-RAM earnings as upstream transportation optimization revenues – that is, as utility earnings that would previously have been recorded in one of the eliminated deferral accounts. In a procedural order in Union's application, the Board directed that Union's classification of its 2011 FT-RAM revenues be dealt with as a preliminary issue in the proceeding.

[12] In its decision on the preliminary issue, the Board rejected Union's classification of its 2011 FT-RAM revenues as utility earnings and concluded instead that the disputed $22 million should be classified as "gas supply cost reductions". As such, the revenues would ordinarily be passed through to ratepayers, and Union would not be entitled to any portion of them.

[13] The Board found that Union had used the FT-RAM program to generate profits on its upstream transportation portfolio on a planned basis – whereas Union's past upstream transportation optimization activities had occurred on an unplanned basis. Because upstream transportation costs are passed through

[1] Firm transportation refers to the quality of upstream transportation. Firm transportation cannot be interrupted by the transportation supplier, whereas interruptible transportation can be interrupted.

entirely to ratepayers, the Board found that Union's planned profit-making on its upstream transportation portfolio was inconsistent with the IRM Agreement and the regulatory principle imbedded in it that a utility "cannot profit from the procurement of gas supply for its customers."

[14] The Board concluded that it was entitled to reclassify the FT-RAM revenues because it was part of its mandate to ensure that revenues were being properly characterized under the IRM Agreement and in a manner that resulted in just and reasonable rates.

[15] While acknowledging that gas supply costs (and gas supply cost reductions) are ordinarily passed through entirely to ratepayers, the Board directed that 90 per cent of the $22 million should be credited to ratepayers and that 10 per cent should be credited to Union as an incentive for generating the revenues. In a subsequent rate order, the Board directed that the funds should be recorded in a newly created deferral account.

[16] Union appealed the Board's decision on the preliminary issue to the Divisional Court.

[17] Before the Divisional Court, Union argued that the Board had already approved the gas supply cost reductions to be credited to ratepayers for 2011 through final rate orders made in Quarterly Rate Adjustment Mechanism ("QRAM") proceedings, which disposed of deferral accounts relating to upstream

gas and transportation costs. Accordingly, Union maintained that by reclassifying Union's 2011 FT-RAM revenues as gas supply cost reductions, the Board engaged in impermissible retroactive ratemaking.

[18] In a split decision, the Divisional Court found that the Board's reclassification of the 2011 FT-RAM revenues did not amount to impermissible retroactive ratemaking. The majority concluded that the revenues at issue were not dealt with in the 2011 QRAM proceedings. Moreover, because the revenues were brought forward as part of the ESM proceeding, they were effectively "encumbered", and therefore subject to further disposition by the Board. The majority held that the Board's statutory rate-making authority is broad and "[does not] in any manner constrain the Board from making orders respecting matters which arose in a previous year but had not been specifically dealt with as a discrete item in the rate-setting process."

[19] Union now appeals to this court with leave and argues that the Board acted unreasonably in reclassifying Union's 2011 FT-RAM revenues as gas supply cost reductions for two reasons.

[20] First, it says the reclassification was an unauthorized departure from the terms of the IRM Agreement, which the Board had approved as the mechanism for setting rates during the IRM period. Second, it says the reclassification amounted to impermissible retroactive ratemaking. This is because gas supply

cost deferral accounts had already been disposed of through final orders in the 2011 QRAM proceedings and because there was no separate deferral account for FT-RAM revenues in relation to which the Board could make a further disposition. According to Union, the Board's decision is thus a classic impermissible attempt to remedy past rates the Board later concluded were excessive.

[21] For the reasons that follow, I would dismiss Union's appeal.

B. BACKGROUND

(1) Union

[22] Union is an Ontario corporation that sells, distributes, transmits and stores natural gas. It does not produce natural gas. From its head office in Chatham, Union services approximately 1.4 million residential, commercial and industrial customers across northern, southwestern and eastern Ontario.

(2) The Board and its Authority

[23] The Board is a statutory tribunal governed by the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Sch. B. Among other powers, the Board has authority to set rates for the sale, transmission, distribution and storage of gas in the natural gas sector: s. 36(1).[2] The Board carries out its rate-setting function by

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[2] The text of relevant provisions under the Act is included in Appendix "A".

issuing orders: s. 19(2). In making orders, the Board is not bound by the terms of any contract: s. 36(1).

[24] Under s. 36(2) of the Act, the Board may "make orders approving or fixing *just and reasonable rates* for the sale of gas by gas transmitters, gas distributors and storage companies, and for the transmission, distribution and storage of gas" (emphasis added).

[25] Just and reasonable rates permit a utility to recover its prudently incurred costs and earn a fair return on invested capital: see, for example, *Power Workers' Union, Canadian Union of Public Employees, Local 1000 v. Ontario (Energy Board)*, 2013 ONCA 359, 116 O.R. (3d) 793, at paras. 13, 30-32, leave to appeal to S.C.C. granted, [2013] S.C.C.A. No. 339, appeal heard and reserved December 3, 2014; *Northwestern Utilities Ltd. v. Edmonton (City)*, [1929] S.C.R. 186, pp. 192-3.

[26] Under s. 36(3) of the Act, "[i]n approving or fixing just and reasonable rates, the Board may adopt any method or technique that it considers appropriate."

[27] Deferral accounts are not defined in the Act. However, under ss. 36(4.1) and (4.2), the Board must dispose of the balances in deferral accounts at specified intervals. Deferral accounts relating to the commodity of natural gas are to be reflected in rates within a maximum of three months, and deferral accounts

relating to other items, including transportation costs, are to be reflected in rates within a maximum of 12 months.

(3) The Board's Practice in Setting Union's Rates

[28] Historically, the Board set Union's natural gas rates following an annual cost of service hearing at which the Board established Union's revenue requirement, consisting of a forecast of Union's costs, including a return on equity, over a future year or test period. As part of the rate-setting process, typically the Board established various deferral accounts to allow it to defer consideration of revenues and expenses that could not be forecast with certainty.

[29] Between 2008 and 2012, Union's natural gas rates were set through a Board-approved Incentive Regulation Mechanism – the IRM Agreement.

[30] During incentive regulation, a utility's base rates are set initially through a cost of service proceeding and then adjusted annually using a pre-approved pricing mechanism intended to encourage productivity or efficiency improvements. If a utility is able to increase revenues or reduce costs during incentive regulation, it is permitted to retain its "over-earnings" in excess of its regulated return on equity – but subject to the terms of any earnings sharing mechanism under which the utility has agreed to share its earnings with its ratepayers.

[31] I will return later to the terms of the IRM Agreement.

(4) Upstream Transportation Optimization

[32] To ensure a consistent supply of gas to its customers, Union holds a portfolio of upstream transportation contracts that provide gas transportation on a firm basis from supply basins across North America to Union's storage, transmission and distribution system in Ontario.

[33] Because it is difficult to predict with accuracy how much firm transportation capacity is required in any given year, as part of maintaining a conservative gas supply plan that will ensure a consistent supply of natural gas, a utility may, from time-to-time, have excess firm transportation capacity.

[34] Traditionally, the Board has passed through the cost of upstream transportation entirely to ratepayers through the use of deferral accounts. However, where a utility was able to generate revenue by disposing of unused transportation capacity through transactions with third parties, the Board has generally permitted the utility to retain some portion of the revenues generated from these transactions to encourage the utility to dispose of the unused capacity. The transactions themselves are generally referred to as "optimization activities" or "transactional services".

[35] Prior to the IRM Agreement, revenue earned from upstream transportation optimization activities was recorded in various deferral accounts. In the past, the Board had ordered that these accounts be cleared at least annually on the basis

that ratepayers receive 75 per cent of the revenues through a rate reduction and Union retain the remaining 25 per cent of revenues.

(5) The IRM Agreement

[36] As indicated above, for the period 2008 to 2012, Union entered into the IRM Agreement with the interveners. In January 2008, the Board approved the IRM Agreement as an acceptable incentive regulation program.

[37] The following aspects of the IRM Agreement are significant for the purposes of this appeal:

- The IRM Agreement identified so-called “Y factors”, which are costs incurred by Union that would be passed through entirely to customers during the term of the IRM Agreement. Items treated as “Y factors” in the IRM Agreement included upstream gas and transportation costs.
- The IRM Agreement eliminated four deferral accounts, which had been previously maintained. In return for closing these accounts, Union increased the optimization margin built into rates from $2.6 million to $6.9 million. Put another way, Union agreed to fund a $4.3 million annual decrease in rates and assumed the risk of earning sufficient optimization revenue to offset that decrease.

- The IRM Agreement included the ESM, which initially provided that utility earnings greater than two per cent above Union's regulated rate of return would be shared 50/50 with ratepayers.
- The IRM Agreement permitted the parties to re-open it if Union's earnings exceeded its regulated return on equity by more than three per cent.

[38] When Union's earnings for 2008 did exceed three per cent, the parties to the IRM Agreement entered into a further Settlement Agreement amending the terms of the IRM Agreement (the "Amending Agreement"). Among other things, the Amending Agreement provided that earnings over three per cent of Union's regulated rate of return were to be shared 90/10 in favour of ratepayers. The Board approved this amendment by order.

(6) QRAM Proceedings

[39] As indicated above, depending on the type of deferral account, the Act requires that they be cleared at least quarterly or annually. Given the frequency with which deferral accounts must be cleared, the Board developed QRAM proceedings. They provide an abbreviated and mechanistic hearing process used to clear some, but not all, deferral accounts.

[40] In 2011, Union brought five deferral accounts forward for disposition every quarter through QRAM proceeding. Some of these accounts included gas

transportation related costs. Union did not bring the disputed $22 million in FT-RAM revenues forward for disposition in any of the 2011 QRAM proceedings.

(7) Union's April 2012 Application

[41] The application giving rise to this appeal was brought in April 2012. As indicated above, Union filed an application at that time seeking an order amending or varying the rates charged to customers as of October 2012. A key purpose of the application was to dispose of 2011 utility earnings in accordance with the ESM.

[42] In its application, Union included as utility earnings total optimization revenues for 2011 of $31.7 million, $22 million of which was attributable to FT-RAM optimization.

(8) Union's 2013 Cost of Service Proceeding

[43] On November 10, 2011, Union filed an application with the Board for an order approving or fixing its rates effective January 1, 2013. The appropriate treatment of FT-RAM revenues was an issue in that proceeding. The cost of service decision is relevant because the Board incorporated the evidentiary record from the 2013 cost of service proceeding as part of the record on the preliminary issue.

C. DECISIONS BELOW

(1) The Board's decision on the Preliminary Issue

[44] Prior to dealing with Union's application, the Board determined that it would address Union's treatment of upstream transportation optimization revenues in 2011 as a preliminary issue.

[45] The Board described the preliminary issue as follows: "Has Union treated the upstream transportation optimization revenues appropriately in 2011 in the context of Union's existing IRM framework?"

[46] In its decision on the preliminary issue, the Board accepted the argument of several interveners that TCPL's FT-RAM program allowed Union to create revenue opportunities by planning to replace higher cost firm upstream transportation services paid for by ratepayers with lower cost upstream transportation arrangements:

> The Board agrees with the submissions of parties that *the utilization of TCPL's FT-RAM program by Union allows Union to manage its upstream transportation arrangements on a planned basis* by leaving pipe empty and flowing gas on a different and cheaper path. The Board finds that *the effect of this activity is that higher upstream transportation costs that are paid for by Union's customers, have been substituted with lower cost upstream transportation arrangements*. [Emphasis added.]

[47] As noted by the Divisional Court, the Board used even stronger language in its companion decision on the related 2012 cost of service proceeding in describing Union's actions. For example, the Board said:

> The Board finds that the record in this proceeding is clear that firm assets are being made available for transactional services on a planned basis, with releases occurring prior to the commencement of the heating season and with capacity being assigned for up to a full year. …
>
> … the record in this proceeding suggests that Union's optimization activities have, in their own right, become a driver of the gas supply plan and are no longer solely a consequence of it.
>
> *The Board finds that Union's ability to "manufacture" optimization opportunities undermines the credibility of Union's gas supply planning process, the planning methodology, and the resulting gas supply plan.*
>
> As submitted by various parties to this proceeding and Board staff, *Union has had an incentive to contract excessive upstream gas transportation services to the detriment of the ratepayer. Union has not filed convincing evidence that the amount and type of upstream gas transportation contracts procured on behalf of ratepayers reflects the objective application of its gas supply planning principles.* [Emphasis added.]

[48] In the light of its finding that Union had acted on a planned basis, the Board concluded that treating FT-RAM revenues as utility earnings was "inconsistent" with the IRM Agreement – and contrary to the regulatory principle inherent in it – that the cost of upstream transportation is a pass-through item from which Union is not entitled to profit:

> The Board finds that Union has used TCPL's FT-RAM program to create a profit from the upstream transportation portfolio and has treated this profit as utility earnings, subject only to the provisions of the earnings sharing mechanism.
>
> *The Board finds that this treatment is inconsistent with the Settlement Agreement on the IRM Framework and contrary to long standing regulatory principle inherent in the IRM Framework that the cost of gas and upstream transportation are to be treated as pass-through items, and therefore that Union cannot profit from the procurement of gas supply for its customers*. [Emphasis added.]

[49] Instead, the Board determined that the monies generated from FT-RAM activities should be treated as gas supply costs savings:

> As such, the Board finds that Union's upstream transportation FT-RAM optimization revenues are gas cost reductions, and are properly considered Y factor items in accordance with Union's IRM Framework.

[50] However, although gas supply cost reductions would normally be passed through completely to ratepayers, the Board noted that "absent an incentive, [Union] may not have undertaken these [optimization] activities."

[51] Accordingly, the Board directed that ratepayers would be entitled to 90 per cent of the $22 million net revenue amount related to Union's 2011 FT-RAM activities in the form of an offset to gas supply costs and that Union would be entitled to receive a 10 per cent incentive for having generated the net revenues.

[52] In the course of its reasons, the Board rejected Union's arguments that reclassifying the FT-RAM revenues would undo the IRM Agreement and amount to retroactive ratemaking.

[53] The Board noted that it was reclassifying revenues based on evidence filed in Union's 2013 cost of service proceeding, which the Board incorporated by reference. The Board stated that the reclassification of revenues "[was] consistent with the IRM Framework".

[54] Moreover, the Board found that it had "an ongoing responsibility to determine whether activities undertaken during the IRM term [were] being characterized in accordance with the IRM Framework and have been characterized in a manner which results in just and reasonable rates."

[55] Accordingly, "the annual disposition of deferral accounts, earnings sharing, and other accounts that are part of Union's IRM Framework is not merely a mechanical exercise." Instead, "it is a process that is informed by evidence relating to the balances in those accounts and whether those balances reflect the appropriate application of the IRM Framework and the regulatory principles inherent in it."

[56] The Board also rejected Union's arguments that its FT-RAM activities were no different than optimization activities or transactional services in which Union had engaged in the past and that treating its FT-RAM activities as gas supply

cost reductions would be inconsistent with the descriptions and historical use of deferral accounts.

[57] The Board found that evidence in prior proceedings led to the conclusion that upstream optimization opportunities were generally only available on an *unplanned* basis. Further, Union had not pointed to any evidence filed prior to the concurrent cost of service proceeding that fully explained how the FT-RAM revenues were being generated.

[58] In this regard, the Board noted that an “information asymmetry … exists” between Union and its ratepayers and that Union had an obligation to make “a much higher level of disclosure than was produced in prior proceedings” concerning “departures or potential departures … from regulatory principle inherent in the IRM Framework”.

[59] Despite its findings concerning the 2011 FT-RAM revenues, the Board rejected submissions from some of the interveners that it should address FT-RAM revenues earned prior to 2011.

[60] The Board directed Union to advise it of the gas supply related deferral account(s) in which the reduction to ratepayers would be recorded and to file a draft accounting order for the account(s).

[61] The Board subsequently issued a decision and rate order on February 28, 2013, under which the revenues from the 2011 FT-RAM optimization activities were to be recorded in a newly created deferral account.

(2) The Divisional Court's Decision

[62] Union appealed the Board's decision on the preliminary issue to the Divisional Court. Before the Divisional Court, Union argued that all 2011 gas supply related costs had been dealt with through final orders in 2011 QRAM proceedings. Accordingly, by reclassifying the utility revenues as gas supply cost reductions to be passed through to ratepayers, the Board varied what were final rate orders and engaged in impermissible retroactive ratemaking.

[63] The majority dismissed the appeal, holding that the Board's findings were clear that the disputed $22 million had not been dealt with as part of the 2011 QRAM proceedings and that Union had not met its disclosure obligations concerning the FT-RAM revenue. Because the "true scope and nature of the FT-RAM program" was only revealed during the 2012 rate hearing, that revenue could only be properly classified following the 2012 hearing. It followed that the $22 million was "encumbered" because "Union, in accordance with the statutory framework and Board policy, was bringing forward its 2011 accounts for review and approval."

[64] During the course of their reasons, the majority stated, “the provisions of section 36 of the Act are liberal in construction and do not in any manner constrain the Board from making orders respecting matters which arose in a previous year but had not been specifically dealt with as a discrete item in the ratesetting process”.

[65] In the dissenting judge’s view, the elimination of the deferral accounts when the IRM Agreement was entered into led to the conclusion “that the intended Y factor under the [IRM Agreement] was gross transportation costs”.

[66] In other words, because the upstream transportation optimization deferral accounts were eliminated, the Y factor described as upstream transportation costs in the IRM Agreement referred to the costs associated with Union’s firm transportation contracts “without regard for any netting or pass-through of profits or losses on the sale of any such contracts.”

[67] Accordingly, under the terms of the IRM Agreement, the FT-RAM revenues were to be treated as utility revenues subject to the ESM because there was “no other account or provision that would mandate different treatment” for them.

[68] The dissenting judge also rejected the Board’s conclusion that a meaningful distinction could be made under the terms of IRM Agreement between FT-RAM revenues and other transactional services revenues. In his view, the Board’s conclusion that a distinction existed between planned and

unplanned upstream transportation optimization activities was not justified. He concluded, "[T]he concept of 'transactional services revenues' does not, by itself, provide a basis for the re-classification of FT-RAM related revenues as gas supply costs."

[69] Having concluded that the Y factor described in the IRM Agreement referred to gross transportation costs – and therefore that FT-RAM revenues were subject to the ESM – the dissenting judge turned to the question of the Board's authority to reclassify such revenues as gas supply cost reductions. He rejected the Board's submission on appeal that the amounts brought forward by Union were "encumbered" and questioned how, in the absence of an applicable deferral account, that condition could arise.

[70] The dissenting judge concluded that neither the IRM Agreement nor the Act authorized the Board to reclassify Union's FT-RAM revenues. Rather, the Board's reclassification of Union's 2011 FT-RAM related earnings for the purposes of the ESM constituted retroactive ratemaking, and was, "by definition, unreasonable".

D. ANALYSIS

(1) Standard of Review

[71] Under s. 33(2) of the Act, an appeal lies to the Divisional Court from an order of the Board "only upon a question of law or jurisdiction".

[72] The parties agree that decisions of the Board are reviewable on appeal to the Divisional Court on a standard of reasonableness. I agree. (See, for example, *Power Workers'*).

(2) Discussion

[73] Union submits that the Board's decision to reclassify the FT-RAM revenues as gas supply cost reductions is unreasonable because it is an unauthorized departure from the terms of the IRM Agreement, which the Board had approved as the mechanism for setting just and reasonable rates during the incentive regulation period, and because it constitutes impermissible retroactive ratemaking.

[74] Union points out that, under the terms of the IRM Agreement, it reduced its revenue requirement in exchange for the elimination of the upstream transportation optimization deferral accounts. Union contends that its FT-RAM optimization activities were no different than other optimization activities in which it had previously engaged and that it is undisputed that, absent the IRM Agreement, such revenues would have fallen within the one of the eliminated upstream transportation optimization deferral accounts. By reclassifying FT-RAM revenues as gas supply cost reductions, the Board effectively unwound the IRM Agreement. Moreover, the reclassification is inconsistent with the Board's past treatment of such revenues.

[75] In any event, all permissible 2011 rate adjustments based on gas supply cost reductions had already been made through final orders in the QRAM proceedings. In the absence of a deferral account that segregated specified amounts for future disposition, reclassifying the FT-RAM revenues from utility earnings to gas supply cost reductions was nothing more than an impermissible attempt to adjust rates that had been previously set based on unanticipated circumstances – namely, the unanticipated amount of revenue Union was able to generate by using the FT-RAM program. By definition, the Board's decision constitutes impermissible retroactive ratemaking.

[76] I would not accept these submissions.

[77] As a starting point, contrary to Union's position, the Board made an explicit finding that monies generated by Union's 2011 FT-RAM activities would not have fallen into one of the deferral accounts eliminated under the IRM Agreement. In the Board's view, this was because Union was using the program to create optimization opportunities on a planned basis, whereas the deferral accounts recorded optimization activities carried out on an unplanned basis:

> The Board notes that *Union has classified the revenues generated from its upstream transportation FT-RAM optimization activities as transactional service revenues because it believes that these activities are no different than its traditional transactional service activities.* However, *the Board finds that a review of the evidence* filed by Union in previous proceedings to answer the

> question: "what are transactional services" *does not lead to this conclusion*.
>
> …
>
> The Board finds that *Union's evidence* in the RP-2003-0063 / EB-2003-0087 proceeding, when taken as whole, *does not support the conclusion that the planned optimization of gas supply related assets would be considered a transactional service. The evidence* in the above noted proceeding *explicitly speaks to the fact that with a balanced gas supply portfolio there will be few, if any, firm assets available to support transactional services on a future planned basis. In the Board's view, this statement speaks to the fact that the portion of utility gas supply assets that is available to support transactional service activities is only the portion of those assets that is temporarily surplus to the gas supply plan as a result of factors beyond Union's control. Therefore, a clear distinction can be made between Union's transactional services (including exchanges) and Union's FT-RAM related activities*. [Emphasis added.]

[78] In my view, the Board's findings that monies generated by Union's 2011 FT-RAM activities were generated on a planned basis, and were thus distinguishable from upstream transportation optimization revenues that would have fallen within the eliminated deferral accounts, are findings of fact that were not subject to review on appeal to the Divisional Court.

[79] In the result, rather than being a departure from the IRM Agreement that had the effect of unwinding the IRM Agreement, the Board's decision was nothing more than a review of the nature of the revenues brought forward for sharing under the ESM and a determination that some of such revenues did not

qualify for that treatment. Accordingly, in my view, the Board's decision cannot be seen as unreasonable on the basis that it was a departure from the IRM Agreement. Nor was its conclusion that the FT-RAM revenues did not qualify for sharing under the ESM unreasonable.

[80] Moreover, I am not convinced that the fact that the FT-RAM revenues were not segregated in a special deferral account relating specifically to gas supply cost reductions means that the Board engaged in impermissible retroactive ratemaking by reclassifying them as gas supply cost reductions. Rather, I conclude that the FT-RAM revenues brought forward by Union for disposition as part of the ESM proceeding were effectively "encumbered" and subject to further disposition by the Board.

[81] This issue requires a discussion of the principle against retroactive ratemaking.

[82] It is well established that an economic regulatory tribunal, such as the Board, operating under a positive approval scheme of ratemaking must exercise its rate-making authority on a prospective basis. Generally speaking, absent express statutory authorization, such a regulator may not exercise its rate-making authority retroactively or retrospectively.

[83] As noted by the Divisional Court majority, the classic explanation for the general presumption against the retroactive operation of statutes is set out in *Young v. Adams*, [1898] A.C. 469, at p. 476:

> [I]t manifestly shocks one's sense of justice that an act legal at the time of doing it should be made unlawful by some new enactment.

[84] In *Bell Canada v. Canada (Canadian Radio-Television and Telecommunications Commission)*, [1989] 1 S.C.R. 1722, ("*Bell Canada 1989*"), at p. 1749, Gonthier J. writing for the court, characterized retroactive ratemaking as ratemaking the purpose of which "is to remedy the imposition of rates approved in the past and found in the final analysis to be excessive."

[85] At p. 1759 of the same case, Gonthier J. explained that "the power to review its own previous final decision on the fairness and reasonableness of rates would threaten the stability of the regulated entity's financial situation."

[86] From the ratepayers' perspective, retroactive ratemaking may create unfairness because it "redistributes the cost of utility service by asking today's customers to pay for the expenses incurred by yesterday's customers": *Atco Gas and Pipelines Ltd. v. Alberta (Utilities Commission)*, 2014 ABCA 28, 566 A.R. 323, at para. 51.

[87] Nonetheless, courts have recognized qualifications on the principle against retroactive ratemaking.

[88] In *Bell Canada 1989*, at pp. 1752-1761, the Supreme Court concluded that the power to make interim orders necessarily implies the power to modify, by final order, the rates created under an interim order.

[89] In *Bell Canada v. Bell Alliant Regional Communications*, 2009 SCC 40, [2009] 2 S.C.R. 764, ("*Bell Alliant*"), the Supreme Court noted, at para. 54, that deferral accounts are "accepted regulatory tools" that "'enabl[e] a regulator to defer consideration of a particular item of expense or revenue that is incapable of being forecast with certainty for the test year'".

[90] Although *Bell Alliant* involved the disposition of funds in a deferral account, at paras. 61 and 63, Abella J. also used the term "encumbered" to explain why the disposition of funds in a deferral account for one-time credits to ratepayers did not constitute impermissible retroactive ratemaking. A key feature of her reasoning was that it was known from the beginning that funds accumulated in the deferral accounts at issue were subject to further disposition by the regulator in the form of credits to ratepayers. She said:

> [61] In my view, because this case concerns encumbered revenues in deferral accounts … we are not dealing with the variation of final rates. As Sharlow J.A. pointed out, [the principle from] *Bell Canada 1989* [that retroactive or retrospective ratesetting is impermissible] is inapplicable because *it was known from the outset in the case before us that Bell Canada would be obliged to use the balance of its deferral account in accordance with the CRTC's subsequent direction*.

…

> [63] In my view, the credits ordered out of the deferral accounts in the case before us are neither retroactive nor retrospective. They do not vary the original rate as approved, which included the deferral accounts, nor do they seek to remedy a deficiency in the rate order through later measures, since *these credits or reductions were contemplated as a possible disposition of the deferral account balances from the beginning. These funds can properly be characterized as encumbered revenues, because the rates always remained subject to the deferral accounts mechanism established in the Price Caps Decision*. The use of deferral accounts therefore precludes a finding of retroactivity or retrospectivity. Furthermore, using deferral accounts to account for the difference between forecast and actual costs and revenues has traditionally been held not to constitute retroactive rate-setting [Citations omitted and emphasis added.]

[91] More recently in *Atco Gas,* the Alberta Court of Appeal explained that "[s]lavish adherence to the use of interim rates and deferral accounts should not prohibit adjustments" in a proper case: at para. 62. Moreover, "[s]imply because a ratemaking decision has an impact on a past rate does not mean it is an impermissible retroactive decision": at para. 56. Rather, "[t]he critical factor for determining whether the regulator is engaging in retroactive ratemaking is the parties' knowledge [that the rates were subject to change]": at para. 56.

[92] In that case, the regulator directed Atco to remove certain surplus assets from its rate base and revenue requirement, and backdated the effective date of the removal to an earlier date. The earlier date was the day after the Alberta

Court of Appeal issued a decision indicating that Atco did not require the regulator's consent to remove the asset from its rate base. Removal of the assets from the rate base and revenue requirement caused a decrease in rates, and since the regulator backdated the effective date of the removal, rates were decreased after the fact.

[93] On appeal to the Alberta Court of Appeal, Atco argued that the regulator could only change the rates by using an interim order or deferral account. The Alberta Court of Appeal rejected that argument. The court found, at para. 53, that "the utility must also be taken to know that the rates will be subject to change as a result of the non-inclusion of those assets in the rate base."

[94] In this case, Union does not dispute that, under the terms of the IRM Agreement, following its year-end, it was obliged to bring forward for the Board's review and approval amounts it classified as utility earnings that were subject to sharing under the ESM. Union also knew, from the outset of the IRM Agreement, that the Board's ESM determination would impact rates. The ESM determination under the IRM Agreement was thus inherently retrospective – and Union always knew that.

[95] Further, on the Board's findings, the manner in which Union generated its 2011 FT-RAM revenues and its classification of those revenues as utility earnings was inconsistent with the IRM Agreement and violated the regulatory

principle inherent in the IRM Agreement that the cost of upstream transportation is a pass-through item and that a utility "cannot profit from the procurement of gas supply for its customers."

[96] Although Union argued that its 2011 FT-RAM activities were no different than its previous upstream optimization activities, the Board made a specific finding that "a clear distinction can be made between Union's [unplanned] transactional services … and Union's [planned] FT-RAM activities."

[97] Significantly, prior to the 2012 hearings, the fact that the 2011 FT-RAM revenues were generated on a planned basis – and thus in a fashion inconsistent with regulatory principle and the IRM Agreement – was uniquely within Union's knowledge.

[98] In this regard, the Board found that Union had an obligation to "be mindful of the information asymmetry that exists between it and [its] ratepayers" and "to disclose departures or potential departures that it intends to make from regulatory principle inherent in the IRM Framework."

[99] In circumstances where Union knew that it was generating its 2011 FT-RAM revenues on a planned basis, Union must be fixed with knowledge, as of the date it generated those revenues, that the Board would be obliged to characterize them as a Y factor, or pass-through item, under the IRM Agreement.

[100] Although the Board had permitted profit-taking on optimization activities in the past, on the Board's findings, the prior optimization activities involved disposing of unplanned surpluses of firm transportation. The 2011 FT-RAM activities were qualitatively different because they involved disposing of planned surpluses of firm transportation. Prior to the 2012 hearings, Union was the only party in a position to know that – and must also be taken to have known that – its actions were inconsistent with the regulatory principle inherent in the IRM Agreement.

[101] In these circumstances, where the ESM determination was inherently retrospective, and where Union failed to disclose in advance the true nature of its intended 2011 FT-RAM activities, it was not unreasonable for the Board to treat Union's 2011 FT-RAM revenues as encumbered and therefore subject to further disposition by the Board in the form of a credit to ratepayers.

[102] Union argues that the Board never made an express finding that Union was acquiring excess firm transportation during 2011. While the Board may not have said so expressly, on a fair reading of their decision on the preliminary issue in combination with their decision on the 2012 cost of service proceeding, in my view, that message is very clear.

[103] Having regard to all the circumstances, I am not persuaded that the majority of the Divisional Court erred in characterizing the 2011 FT-RAM

revenues that Union brought forward in its 2012 application as encumbered or that the Board's decision to reclassify those revenues as gas supply cost reductions was unreasonable.

E. DISPOSITION

[104] Based on the foregoing reasons, the appeal is dismissed.

[105] Neither party requested costs and none are awarded.

Released:

"AH"
"JUN 22 2015"

"Janet Simmons J.A."
"I agree Alexandra Hoy A.C.J.O."
"I agree M. Tulloch J.A."

Appendix "A"

Ontario Energy Board Act, 1998, S.O. 1998, c. 15, Sch. B.

19. (2) The Board shall make any determination in a proceeding by order.

33. (1) An appeal lies to the Divisional Court from,

(a) an order of the Board …

(2) An appeal may be made only upon a question of law or jurisdiction and must be commenced not later than 30 days after the making of the order or rule or the issuance of the code.

36. (1) No gas transmitter, gas distributor or storage company shall sell gas or charge for the transmission, distribution or storage of gas except in accordance with an order of the Board, which is not bound by the terms of any contract.

…(2) The Board may make orders approving or fixing just and reasonable rates for the sale of gas by gas transmitters, gas distributors and storage companies, and for the transmission, distribution and storage of gas.

(3) In approving or fixing just and reasonable rates, the Board may adopt any method or technique that it considers appropriate.

…

(4.1) If a gas distributor has a deferral or variance account that relates to the commodity of gas, the Board shall, at least once every three months, make an order under this section that determines whether and how amounts recorded in the account shall be reflected in rates.

(4.2) If a gas distributor has a deferral or variance account that does not relate to the commodity of gas, the Board shall, at least once every 12 months, or such shorter period as is prescribed by the regulations, make an order under this section that determines whether and how amounts recorded in the account shall be reflected in rates.

6

** Preliminary Version **

Case Name:

ATCO Gas & Pipelines Ltd. v. Alberta (Energy & Utilities Board)

City of Calgary, appellant/respondent on cross-appeal;
v.
ATCO Gas and Pipelines Ltd., respondent/appellant on cross-appeal, and
Alberta Energy and Utilities Board, Ontario Energy Board, Enbridge Gas Distribution Inc. and Union Gas Limited, interveners.

[2006] S.C.J. No. 4

[2006] A.C.S. no 4

2006 SCC 4

2006 CSC 4

[2006] 1 S.C.R. 140

[2006] 1 R.C.S. 140

263 D.L.R. (4th) 193

344 N.R. 293

[2006] 5 W.W.R. 1

J.E. 2006-358

54 Alta. L.R. (4th) 1

380 A.R. 1

39 Admin. L.R. (4th) 159

145 A.C.W.S. (3d) 725

EYB 2006-100901

2006 CarswellAlta 139

File No.: 30247.

Supreme Court of Canada

Heard: May 11, 2005;
Judgment: February 9, 2006.

Present: McLachlin C.J. and Bastarache, Binnie, LeBel, Deschamps, Fish and Charron JJ.

(149 paras.)

Appeal From:

ON APPEAL FROM THE COURT OF APPEAL OF ALBERTA

Subsequent History:

NOTE: This document is subject to editorial revision before its reproduction in final form in the Canada Supreme Court Reports.

Catchwords:

Administrative law -- Boards and tribunals -- Regulatory boards -- Jurisdiction -- Doctrine of jurisdiction by necessary implication -- Natural gas public utility applying to Alberta Energy and Utilities Board to approve sale of buildings and land no longer required in supplying natural gas -- Board approving sale subject to condition that portion of sale proceeds be allocated to ratepaying customers of utility -- Whether Board had explicit or implicit jurisdiction to allocate proceeds of sale -- If so, whether Board's decision to exercise discretion to protect public interest by allocating proceeds of utility asset sale to customers reasonable -- Alberta Energy and Utilities Board Act, R.S.A. 2000, c. A-17, s. 15(3) -- Public Utilities Board Act, R.S.A. 2000, c. P-45, s. 37 -- Gas Utilities Act, R.S.A. 2000, c. G-5, s. 26(2).

Administrative law -- Judicial review -- Standard of review -- Alberta Energy and Utilities Board -- Standard of review applicable to Board's jurisdiction to allocate proceeds from sale of public utility assets to ratepayers -- Standard of review applicable to Board's decision to exercise discretion to allocate proceeds of sale -- Alberta Energy and Utilities Board Act, R.S.A. 2000, c. A-17, s. 15(3) -- Public Utilities Board Act, R.S.A. 2000, c. P-45, s. 37 -- Gas Utilities Act, R.S.A. 2000, c. G-5, s. 26(2).

Summary:

ATCO is a public utility in Alberta which delivers natural gas. A division of ATCO filed an application with the Alberta Energy and Utilities Board for approval of the sale of buildings and land located in Calgary, as required by the *Gas Utilities Act* ("GUA"). According to ATCO, the property was no longer used or useful for the provision of utility services, and the sale would not cause any harm to ratepaying customers. ATCO requested that the Board approve the

sale transaction, as well as the proposed disposition of the sale proceeds: to retire the remaining book value of the sold assets, to recover the disposition costs, and to recognize that the balance of the profits resulting from the sale should be paid to ATCO's shareholders. The customers' interests were represented by the City of Calgary, who opposed ATCO's position with respect to the disposition of the sale proceeds to shareholders.

Persuaded that customers would not be harmed by the sale, the Board approved the sale transaction on the basis that customers would not "be exposed to the risk of financial harm as a result of the Sale that could not be examined in a future proceeding". In a second decision, the Board determined the allocation of net sale proceeds. The Board held that it had the jurisdiction to approve a proposed disposition of sale proceeds subject to appropriate conditions to protect the public interest, pursuant to the powers granted to it under s. 15(3) of the *Alberta Energy and Utilities Board Act* ("AEUBA"). The Board applied a formula which recognizes profits realized when proceeds of sale exceed the original cost can be shared between customers and shareholders, and allocated a portion of the net gain on the sale to the ratepaying customers. The Alberta Court of Appeal set aside the Board's decision, referring the matter back to the Board to allocate the entire remainder of the proceeds to ATCO.

Held (McLachlin C.J. and Binnie and Fish JJ. dissenting): The appeal is dismissed and the cross-appeal is allowed.

Per **Bastarache**, LeBel, Deschamps and Charron JJ.: When the relevant factors of the pragmatic and functional approach are properly considered, the standard of review applicable to the Board's decision on the issue of jurisdiction is correctness. Here, the Board did not have the jurisdiction to allocate the proceeds of the sale of the utility's asset. The Court of Appeal made no error of fact or law when it concluded that the Board acted beyond its jurisdiction by misapprehending its statutory and common law authority. However, the Court of Appeal erred when it did not go on to conclude that the Board has no jurisdiction to allocate *any* portion of the proceeds of sale of the property to ratepayers. [paras. 21-34]

The interpretation of the AEUBA, the *Public Utilities Board Act* ("PUBA") and the GUA can lead to only one conclusion: the Board does not have the prerogative to decide on the distribution of the net gain from the sale of assets of a utility. On their grammatical and ordinary meaning, s. 26(2) GUA, s. 15(3) AEUBA and s. 37 PUBA are silent as to the Board's power to deal with sale proceeds. Section 26(2) GUA conferred on the Board the power to approve a transaction without more. The intended meaning of the Board's power pursuant to s. 15(3) AEUBA to impose conditions on an order that the Board considers necessary in the public interest, as well as the general power in s. 37 PUBA, is lost when the provisions are read in isolation. They are, on their own, vague and open-ended. It would be absurd to allow the Board an unfettered discretion to attach any condition it wishes to any order it makes. While the concept of "public interest" is very wide and elastic, the Board cannot be given total discretion over its limitations. These seemingly broad powers must be interpreted within the entire context of the statutes which are meant to balance the need to protect consumers as well as the property rights retained by owners, as recognized in a free market economy. The context indicates that the limits of the Board's powers are grounded in its main function of fixing just and reasonable rates and in protecting the integrity and dependability of the supply system. [para. 7] [paras. 41-46]

An examination of the historical background of public utilities regulation in Alberta generally, and the legislation in respect of the powers of the Alberta Energy and Utilities Board in particular, reveals that nowhere is there a mention of the authority for the Board to allocate proceeds from a sale or the discretion of the Board to interfere with ownership rights. Moreover, although the Board may seem to possess a variety of powers and functions, it is manifest from a reading of the AEUBA, the PUBA and the GUA that the principal function of the Board in respect of public utilities, is the determination of rates. Its power to supervise the finances of these companies and their operations, although wide, is in practice incidental to fixing rates. The goals of sustainability, equity and efficiency, which underlie the reasoning as to how rates are fixed, have resulted in an economic and social arrangement which ensures that all customers have access to the utility at a fair price -- nothing more. The rates paid by customers do not incorporate acquiring ownership or control of the utility's assets. The object of the statutes is to protect both the customer and the investor, and the Board's responsibility is to maintain a tariff that enhances the economic benefits to consumers and investors of the utility. This well-balanced regulatory arrangement does not, however, cancel the private nature of the utility. The fact that the utility is given the opportunity to make a profit on its services and a fair return on its investment in its assets should not and cannot stop the utility from benefiting from the profits which follow the sale of assets. Neither is the utility protected from losses incurred from the sale of assets. The Board misdirected itself by confusing the interests of the customers in obtaining safe and efficient utility service with an interest in the underlying assets owned only by the utility. [para. 7] [paras. 54-69]

Not only is the power to allocate the proceeds of the sale absent from the explicit language of the legislation, but it cannot be implied from the statutory regime as necessarily incidental to the explicit powers. For the doctrine of jurisdiction by necessary implication to apply, there must be evidence that the exercise of that power is a practical necessity for the Board to accomplish the objects prescribed by the legislature, something which is absent in this case. Not only is the authority to attach a condition to allocate the proceeds of a sale to a particular party unnecessary for the Board to accomplish its role, but deciding otherwise would lead to the conclusion that broadly drawn powers, such as those found in the AEUBA, the GUA and the PUBA, can be interpreted so as to encroach on the economic freedom of the utility, depriving it of its rights. If the Alberta legislature wishes to confer on ratepayers the economic benefits resulting from the sale of utility assets, it can expressly provide for this in the legislation. [para. 39] [paras. 77-80]

Notwithstanding the conclusion that the Board lacked jurisdiction, its decision to exercise its discretion to protect the public interest by allocating the sale proceeds as it did to ratepaying customers did not meet a reasonable standard. When it explicitly concluded that no harm would ensue to customers from the sale of the asset, the Board did not identify any public interest which required protection and there was, therefore, nothing to trigger the exercise of the discretion to allocate the proceeds of sale. Finally, it cannot be concluded that the Board's allocation was reasonable when it wrongly assumed that ratepayers had acquired a proprietary interest in the utility's assets because assets were a factor in the rate-setting process. [paras. 82-85]

Per McLachlin C.J. and **Binnie** and Fish JJ. (dissenting) : The Board's decision should be restored. Section 15(3) AEUBA authorized the Board, in dealing with ATCO's application to approve the sale of the subject land and buildings, to "impose any additional conditions that the Board considers necessary in the public interest". In the exercise of that authority, and having regard to the Board's "general supervision over all gas utilities, and the owners of them" pursuant to s. 22(1) GUA, the Board made an allocation of the net gain for public policy reasons. The Board's discretion is not unlimited and must be exercised in good faith for its intended purpose. Here, in allocating one third of the net gain to ATCO and two thirds to the rate base, the Board explained that it was proper to balance the interests of both shareholders and ratepayers. In the Board's view to award the entire gain to the ratepayers would deny the utility an incentive to increase its efficiency and reduce its costs, but on the other hand to award the entire gain to the utility might encourage speculation in non-depreciable property or motivate the utility to identify and dispose of properties which have appreciated for reasons other than the best interest of the regulated business. Although it was open to the Board to allow ATCO's application for the entire profit, the solution it adopted in this case is well within the range of reasonable options. The "public interest" is largely and inherently a matter of opinion and discretion. While the statutory framework of utilities regulation varies from jurisdiction to jurisdiction, Alberta's grant of authority to its Board is more generous than most. The Court should not substitute its own view of what is "necessary in the public interest". The Board's decision made in the exercise of its jurisdiction was within the range of established regulatory opinion, whether the proper standard of review in that regard is patent unreasonableness or simple reasonableness. [paras. 91-92] [paras. 98-99] [para. 110] [para. 113] [para. 122] [para. 148]

ATCO's submission that an allocation of profit to the customers would amount to a confiscation of the corporation's property overlooks the obvious difference between investment in an unregulated business and investment in a regulated utility where the ratepayers carry the costs and the regulator sets the return on investment, not the marketplace. The Board's response cannot be considered "confiscatory" in any proper use of the term, and is well within the range of what is regarded in comparable jurisdictions as an appropriate regulatory allocation of the gain on sale of land whose original investment has been included by the utility itself in its rate base. Similarly, ATCO's argument that the Board engaged in impermissible retroactive ratemaking should not be accepted. The Board proposed to apply a portion of the expected profit to future ratemaking. The effect of the order is prospective not retroactive. Fixing the going-forward rate of return, as well as general supervision of "all gas utilities and the owners of them", were matters squarely within the Board's statutory mandate. ATCO also submits in its cross-appeal that the Court of Appeal erred in drawing a distinction between gains on sale of land whose original cost is not depreciated and depreciated property, such as buildings. A review of regulatory practice shows that many, but not all, regulators reject the relevance of this distinction. The point is not that the regulator must reject any such distinction but, rather, that the distinction does not have the controlling weight as contended by ATCO. In Alberta, it is up to the Board to determine what allocations are necessary in the public interest as conditions of the approval of sale. Finally, ATCO's contention that it alone is burdened with the risk on land that declines in value overlooks the fact that in a falling market the utility continues to be entitled to a rate of return on its original investment, even if the market value at the time is substantially less than its original investment. Further, it seems such losses are taken into account in the ongoing rate-setting process. [para. 93] [paras. 123-147]

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By Bastarache J.

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By Binnie J. (dissenting)

Atco Ltd. v. Calgary Power Ltd., [1982] 2 S.C.R. 557; C.U.P.E. v. Ontario (Minister of Labour), [2003] 1 S.C.R. 539, 2003 SCC 29; TransAlta Utilities Corp. v. Public Utilities Board (Alta.) (1986), 68 A.R. 171; Dr. Q v. College of Physicians and Surgeons of British Columbia, [2003] 1 S.C.R. 226, 2003 SCC 19; Calgary Power Ltd. v. Copithorne, [1959] S.C.R. 24; United Brotherhood of Carpenters and Joiners of America, Local 579 v. Bradco Construction Ltd.,

[1993] 2 S.C.R. 316; Pezim v. British Columbia (Superintendent of Brokers), [1994] 2 S.C.R. 557; Memorial Gardens Association (Canada) Ltd. v. Colwood Cemetery Co., [1958] S.C.R. 353; Union Gas Co. of Canada v. Sydenham Gas and Petroleum Co., [1957] S.C.R. 185; Re C.T.C. Dealer Holdings Ltd. and Ontario Securities Commission (1987), 59 O.R. (2d) 79; Committee for the Equal Treatment of Asbestos Minority Shareholders v. Ontario (Securities Commission), [2001] 2 S.C.R. 132, 2001 SCC 37; Re Consumer's Gas Co. (1976), E.B.R.O. 341-I; Re Boston Gas Co. (1982), 49 P.U.R. 4th 1; Re Consumer's Gas Co. (1991), E.B.R.O. 465; Re Natural Resource Gas Ltd., RP-2002-0147, EB-2002-0446; Yukon Energy Corp. v. Utilities Board (1996), 74 B.C.A.C. 58, 121 W.A.C. 58; Re Arizona Public Service Co. (1988), 91 P.U.R. 4th 337, 1988 WL 391394; Re Southern California Water Co. (1992), 43 C.P.U.C. 2d 596, 1992 WL 584058; Re Southern California Gas Co. (1990), 39 C.P.U.C. 2d 166, 118 P.U.R. 4th 81, 1990 WL 488654; Democratic Central Committee of the District of Columbia v. Washington Metropolitan Area Transit Commission, 485 F.2d 786 (1973); Board of Public Utility Commissioners v. New York Telephone Co., 271 U.S. 23 (1926); Northwestern Utilities Ltd. v. City of Edmonton, [1979] 1 S.C.R. 684; New York Water Service Corp. v. Public Service Commission, 208 N.Y.S.2d 587 (1960); Re Compliance with the Energy Policy Act of 1992 (1995), 62 C.P.U.C. 2d 517; Re California Water Service Co. (1996), 66 C.P.U.C. 2d 100, 1996 WL 293205; TransAlta Utilities Corp. (1984), Alta. P.U.B. Decision No. E84116; Alberta Government Telephones (1984), Alta. P.U.B. Decision No. E84081; TransAlta Utilities Corp. (1984), Alta. P.U.B. Decision No. E84115; Re Gas Utilities Act and Public Utilities Board Act (1984), Alta. P.U.B. Decision No. E84113.

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Interpretation Act, R.S.A. 2000, c. I-8, s. 10.

Public Utilities Act, S.A. 1915, c. 6, ss. 21, 23, 24, 29(g).

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History and Disposition:

APPEAL and CROSS-APPEAL from a judgment of the Alberta Court of Appeal (Wittmann J.A. and LoVecchio J. (ad hoc)) (2004), 24 Alta. L.R. (4th) 205, 339 A.R. 250; 312 W.A.C. 250, [2004] 4 W.W.R. 239, [2004] A.J. No. 45 (QL), 2004 ABCA 3, reversing a decision of the Alberta Energy and Utilities Board, Decision No. 2002-037, [2002] A.E.U.B.D. No. 52 (QL). Appeal dismissed and cross-appeal allowed, McLachlin C.J. and Binnie and Fish JJ. dissenting.

Counsel:

Brian K. O'Ferrall and Daron K. Naffin, for the appellant/respondent on cross-appeal.

Clifton D. O'Brien, Q.C., Lawrence E. Smith, Q.C., H. Martin Kay, Q.C., and Laurie A. Goldbach, for the respondent/appellant on cross-appeal.

J. Richard McKee and Renée Marx, for the intervener the Alberta Energy and Utilities Board.

Written submissions only by George Vegh and Michael W. Lyle, for the intervener the Ontario Energy Board.

Written submissions only by Michael D. Schafler and J.L. McDougall, Q.C., for the intervener Enbridge Gas Distribution Inc.

Written submissions only by Michael A. Penny and Susan Kushneryk, for the intervener Union Gas Limited.

[Editor's note: A corrigendum was published by the Court April 24, 2006. The corrections have been incorporated in this document and the text of the corrigendum is appended to the end of the judgment.]

The judgment of Bastarache, LeBel, Deschamps and Charron JJ. was delivered by

BASTARACHE J.:--

1. Introduction

1 At the heart of this appeal is the issue of the jurisdiction of an administrative board. More specifically, the Court must consider whether, on the appropriate standard of review, this utility board appropriately set out the limits of its powers and discretion.

2 Few areas of our lives are now untouched by regulation. Telephone, rail, airline, trucking, foreign investment, insurance, capital markets, broadcasting licences and content, banking, food, drug and safety standards, are just a few of the objects of public regulations in Canada: M. J. Trebilcock, "The Consumer Interest and Regulatory Reform", in G. B. Doern, ed., *The Regulatory Process in Canada* (1978), 94. Discretion is central to the regulatory agency policy process, but this discretion will vary from one administrative body to another (see C. L. Brown-John, *Canadian Regulatory Agencies: Quis custodiet ipsos custodes?* (1981), at p. 29). More importantly, in exercising this discretion, statutory bodies must respect the confines of their jurisdiction: they cannot trespass in areas where the legislature has not assigned them authority (see D. J. Mullan, *Administrative Law* (2001), at pp. 9-10).

3 The business of energy and utilities is no exception to this regulatory framework. The respondent in this case is a public utility in Alberta which delivers natural gas. This public utility is nothing more than a private corporation subject to certain regulatory constraints. Fundamentally, it is like any other privately held company: it obtains the necessary funding from investors through public issues of shares in stock and bond markets; it is the sole owner of the resources, land and other assets; it constructs plants, purchases equipment, and contracts with employees to provide the services; it realizes profits resulting from the application of the rates approved by the Alberta Energy and Utilities Board (the "Board") (see P. W. MacAvoy and J. G. Sidak, "The Efficient Allocation of Proceeds from a Utility's Sale of Assets" (2001), 22 Energy L.J. 233, at p. 234). That said, one cannot ignore the important feature which makes a public utility so distinct: it must answer to a regulator. Public utilities are typically natural monopolies: technology and demand are such that fixed costs are lower for a single firm to supply the market than would be the case where there is duplication of services by different companies in a competitive environment (see A. E. Kahn, *The Economics of Regulation: Principles and Institutions* (1988), vol. 1, at p. 11; B. W. F. Depoorter, "Regulation of Natural Monopoly", in B. Bouckaert and G. De Geest, eds., *Encyclopedia of Law and Economics* (2000), vol. III, 498; J. S. Netz, "Price Regulation: A (Non-Technical) Overview", in B. Bouckaert and G. De Geest, eds., *Encyclopedia of Law and Economics* (2000), vol. III, 396, at p. 398; A. J. Black, "Responsible Regulation: Incentive Rates for Natural Gas Pipelines" (1992), 28 *Tulsa L.J.* 349, at p. 351). Efficiency of production is promoted under this model. However, governments have purported to move away from this theoretical concept and have adopted what can only be described as a "regulated monopoly". The utility regulations exist to protect the public from monopolistic behaviour and the consequent inelasticity of demand while ensuring the continued quality of an essential service (see Kahn, at p. 11).

4 As in any business venture, public utilities make business decisions, their ultimate goal being to maximize the residual benefits to shareholders. However, the regulator limits the utility's managerial discretion over key decisions, including prices, service offerings and the prudency of plant and equipment investment decisions. And more relevant to this case, the utility, outside the ordinary course of business, is limited in its right to sell assets it owns: it must obtain authorization from its regulator before selling an asset previously used to produce regulated services (see MacAvoy and Sidak, at p. 234).

5 Against this backdrop, the Court is being asked to determine whether the Board has jurisdiction pursuant to its enabling statutes to allocate a portion of the net gain on the sale of a now discarded utility asset to the rate-paying customers of the utility when approving the sale. Subsequently, if this first question is answered affirmatively, the Court must consider whether the Board's exercise of its jurisdiction was reasonable and within the limits of its jurisdiction: was it allowed, in the circumstances of this case, to allocate a portion of the net gain on the sale of the utility to the rate-paying customers?

6 The customers' interests are represented in this case by the City of Calgary (the "City") which argues that the Board can determine how to allocate the proceeds pursuant to its power to approve the sale and protect the public interest. I find this position unconvincing.

7 The interpretation of the *Alberta Energy and Utilities Board Act*, R.S.A. 2000, c. A-17 ("AEUBA"), the *Public Utilities Board Act*, R.S.A. 2000, c. P-45 ("PUBA"), and the *Gas Utilities Act*, R.S.A. 2000, c. G-5 ("GUA") (see Appendix for the relevant provisions of these three statutes), can lead to only one conclusion: the Board does not have the prerogative to decide on the distribution of the net gain from the sale of assets of a utility. The Board's seemingly broad powers to make any order and to impose any additional conditions that are necessary in the public interest has to be interpreted within the entire context of the statutes which are meant to balance the need to protect consumers as well as the property rights retained by owners, as recognized in a free market economy. The limits of the powers of the Board are grounded in its main function of fixing just and reasonable rates ("rate setting") and in protecting the integrity and dependability of the supply system.

1.1 *Overview of the Facts*

8 ATCO Gas - South ("AGS"), which is a division of ATCO Gas and Pipelines Ltd. ("ATCO"), filed an application by letter with the Board pursuant to s. 25.1(2) (now s. 26(2)) of the GUA, for approval of the sale of its properties located in Calgary known as Calgary Stores Block (the "property"). The property consisted of land and buildings; however, the main value was in the land, and the purchaser intended to and did eventually demolish the buildings and redevelop the land. According to AGS, the property was no longer used or useful for the provision of utility services, and the sale would not cause any harm to customers. In fact, AGS suggested that the sale would result in cost savings to customers, by allowing the net book value of the property to be retired and withdrawn from the rate base, thereby reducing rates. ATCO requested that the Board approve the sale transaction and the disposition of the sale proceeds to retire the remaining book value of the sold assets, to recover the disposition costs, and to recognize the balance of the profits resulting from the sale of the plant should be paid to shareholders. The Board dealt with the application in writing, without witnesses or an oral hearing. Other parties making written submissions to the Board were the City of Calgary, the Federation of Alberta Gas Co-ops Ltd., Gas Alberta Inc. and the Municipal Interveners , who all opposed ATCO's position with respect to the disposition of the sale proceeds to shareholders.

1.2 *Judicial History*

1.2.1 <u>Alberta Energy and Utilities Board</u>

1.2.1.1 *Decision 2001-78 (Atco Gas and Pipelines Ltd.)*

9 In a first decision, which considered ATCO's application to approve the sale of the property, the Board employed a "no-harm" test, assessing the potential impact on both rates and the level of service to customers and the prudence of the sale transaction, taking into account the purchaser and tender or sale process followed. The Board was of the view that the test had been satisfied. It was persuaded that customers would not be harmed by the sale, given that a prudent lease arrangement to replace the sold facility had been concluded. The Board was satisfied that there would not be a negative impact on customers' rates, at least during the five-year initial term of the lease. In fact, the Board concluded that there would be cost savings to the customers and that there would be no impact on the level of service to customers as a result of the sale. It did not make a finding on the specific impact on future operating costs; for example, it did not consider the costs of the lease arrangement entered into by ATCO. The Board noted that those costs could be reviewed by the Board in a future general rate application brought by interested parties.

1.2.1.2 *Decision 2002-037*, [2002] A.E.U.B. No. 52 (QL)

10 In a second decision, the Board determined the allocation of net sale proceeds. It reviewed the regulatory policy and general principles which affected the decision, although no specific matters are enumerated for consideration in the applicable legislative provisions. The Board had previously developed a "no-harm" test, and it reviewed the rationale for the test as summarized in its Alta. E.U.B. Decision 2001-65, *Atco Gas-North, A Division of Atco Gas and Pipelines Ltd.*: "The Board considers that its power to mitigate or offset potential harm to customers by allocating part or all of the sale proceeds to them, flows from its very broad mandate to protect consumers in the public interest (p. 16)."

11 The Board went on to discuss the implications of the Alberta Court of Appeal decision in *TransAlta Utilities Corp. v. Public Utilities Board (Alta.)* (1986), 68 A.R. 171, referring to various decisions it had rendered in the past. Quoting from Alta. E.U.B. Decision 2000-41 (*TransAlta Utilities Corp.*), the Board summarized the "*TransAlta Formula*" (para. 27):

> In subsequent decisions, the Board has interpreted the Court of Appeal's conclusion to mean that where the sale price exceeds the original cost of the assets, shareholders are entitled to net book value (in historical dollars), customers are entitled to the difference between net book value and original cost, and any appreciation in the value of the assets (i.e. the difference between original cost and the sale price) is to be shared by shareholders and customers. The amount to be shared by each is determined by multiplying the ratio of sale price/original cost to the net book value (for shareholders) and the difference between original cost and net book value (for customers). However, where the sale price does not exceed original cost, customers are entitled to all of the gain on sale.

The Board also referred to Decision 2001-65, where it had clarified the following (para. 28):

> In the Board's view, if the TransAlta Formula yields a result greater than the no-harm amount, customers are entitled to the greater amount. If the TransAlta Formula yields a result less than the no-harm amount, customers are entitled to the no-harm amount. In the Board's view, this approach is consistent with its historical application of the TransAlta Formula.

12 On the issue of its jurisdiction to allocate the net proceeds of a sale, the Board in the present case stated, at paras. 47-49:

> The fact that a regulated utility must seek Board approval before disposing of its assets is sufficient indication of the limitations placed by the legislature on the property rights of a utility. In appropriate circumstances, the Board clearly has the power to prevent a utility from disposing of its property. In the Board's view it also follows that the Board can approve a disposition subject to appropriate conditions to protect customer interests.

> Regarding AGS's argument that allocating more than the no-harm amount to customers would amount to retrospective ratemaking, the Board again notes the decision in the TransAlta Appeal. The Court of Appeal accepted that the Board could include in the definition of "revenue" an amount payable to customers representing excess depreciation paid by them through past rates. In the Board's view, no question of retrospective ratemaking arises in cases where previously regulated rate base assets are being disposed of out of rate base and the Board applies the TransAlta Formula.

> The Board is not persuaded by the Company's argument that the Stores Block assets are now 'non-utility' by virtue of being 'no longer required for utility service'. The Board notes that

> the assets could still be providing service to regulated customers. In fact, the services formerly provided by the Stores Block assets continue to be required, but will be provided from existing and newly leased facilities. Furthermore, the Board notes that even when an asset and the associated service it was providing to customers is no longer required the Board has previously allocated more than the no-harm amount to customers where proceeds have exceeded the original cost of the asset.

13 The Board went on to apply the no-harm test to the present facts. It noted that in its decision on the application for the approval of the sale, it had already considered the no-harm test to be satisfied. However, in that first decision, it had not made a finding with respect to the specific impact on future operating costs, including the particular lease arrangement being entered into by ATCO.

14 The Board then reviewed the submissions with respect to the allocation of the net gain and rejected the submission that if the new owner had no use of the buildings on the land, this should affect the allocation of net proceeds. The Board held that the buildings did have some present value but did not find it necessary to fix a specific value. The Board recognized and confirmed that the *TransAlta Formula* was one whereby the "windfall" realized when the proceeds of sale exceed the original cost could be shared between customers and shareholders. It held that it should apply the formula in this case and that it would consider the gain on the transaction as a whole, not distinguishing between the proceeds allocated to land separately from the proceeds allocated to buildings.

15 With respect to allocation of the gain between customers and shareholders of ATCO, the Board tried to balance the interests of both the customers' desire for safe reliable service at a reasonable cost with the provision of a fair return on the investment made by the company (paras. 112-13):

> To award the entire net gain on the land and buildings to the customers, while beneficial to the customers, could establish an environment that may deter the process wherein the company continually assesses its operation to identify, evaluate, and select options that continually increase efficiency and reduce costs.
>
> Conversely, to award the entire net gain to the company may establish an environment where a regulated utility company might be moved to speculate in non-depreciable property or result in the company being motivated to identify and sell existing properties where appreciation has already occurred.

16 The Board went on to conclude that the sharing of the net gain on the sale of the land and buildings collectively, in accordance with the *TransAlta Formula*, was equitable in the circumstances of this application and was consistent with past Board decisions.

17 The Board determined that from the gross proceeds of $6,550,000, ATCO should receive $465,000 to cover the cost of disposition ($265,000) and the provision for environmental remediation ($200,000), the shareholders should receive $2,014,690, and $4,070,310 should go to the customers. Of the amount credited to shareholders, $225,245 was to be used to remove the remaining net book value of the property from ATCO's accounts. Of the amount allocated to customers, $3,045,813 was allocated to ATCO Gas - South customers and $1,024,497 to ATCO Pipelines - South customers.

1.2.2 Court of Appeal of Alberta ((2004), 24 Alta. L.R. (4th) 205, 2004 ABCA 3)

18 ATCO appealed the Board's decision. It argued that the Board did not have any jurisdiction to allocate the proceeds of sale and that the proceeds should have been allocated entirely to the shareholders. In its view, allowing customers to share in the proceeds of sale would result in them benefiting twice, since they had been spared the costs of renovating the sold assets and would enjoy cost savings from the lease arrangements. The Court of Appeal of Alberta agreed with ATCO, allowing the appeal and setting aside the Board's decision. The matter was referred back to the Board, and the Board was directed to allocate the entire amount appearing in Line 11 of the allocation of proceeds, entitled "Remainder to be Shared" to ATCO. For the reasons that follow, the Court of Appeal's decision should be upheld, in part; it did not err when it held that the Board did not have the jurisdiction to allocate the proceeds of the sale to ratepayers.

2. Analysis

2.1 *Issues*

19 There is an appeal and a cross-appeal in this case: an appeal by the City in which it submits that, contrary to the Court of Appeal's decision, the Board had jurisdiction to allocate a portion of the net gain on the sale of a utility asset to the rate-paying customers, even where no harm to the public was found at the time the Board approved the sale, and a cross-appeal by ATCO in which it questions the Board's jurisdiction to allocate any of ATCO's proceeds from the sale to customers. In particular, ATCO contends that the Board has no jurisdiction to make an allocation to rate-paying customers, equivalent to the accumulated depreciation calculated for prior years. No matter how the issue is framed, it is evident that the crux of this appeal lies in whether the Board has the jurisdiction to distribute the gain on the sale of a utility company's asset.

20 Given my conclusion on this issue, it is not necessary for me to consider whether the Board's allocation of the proceeds in this case was reasonable. Nevertheless, as I note at para. 82, I will direct my attention briefly to the question of the exercise of discretion in view of my colleague's reasons.

2.2 *Standard of Review*

21 As this appeal stems from an administrative body's decision, it is necessary to determine the appropriate level of deference which must be shown to the body. Wittman J.A., writing for the Court of Appeal, concluded that the issue of jurisdiction of the Board attracted a standard of correctness. ATCO concurs with this conclusion. I agree. No deference should be shown for the Board's decision with regard to its jurisdiction on the allocation of the net gain on sale of assets. An inquiry into the factors enunciated by this Court in *Pushpanathan v. Canada (Minister of Citizenship and Immigration)*, [1998] 1 S.C.R. 982, confirms this conclusion, as does the reasoning in *United Taxi Drivers' Fellowship of Southern Alberta v. Calgary (City)*, [2004] 1 S.C.R. 485, 2004 SCC 19.

22 Although it is not necessary to conduct a full analysis of the standard of review in this case, I will address the issue briefly in light of the fact that Binnie J. deals with the exercise of discretion in his reasons for judgment. The four factors that need to be canvassed in order to determine the appropriate standard of review of an administrative tribunal decision are: 1) the existence of a privative clause; 2) the expertise of the tribunal/board; 3) the purpose of the governing legislation and the particular provisions; and 4) the nature of the problem (*Pushpanathan*, at paras. 29-38).

23 In the case at bar, one should avoid a hasty characterizing of the issue as "jurisdictional" and subsequently be tempted to skip the pragmatic and functional analysis. A complete examination of the factors is required.

24 First, s. 26(1) of the AEUBA grants a right of appeal, but in a limited way. Appeals are allowed on a question of jurisdiction or law and only after leave to appeal is obtained from a judge:

> **26(1)** Subject to subsection (2), an appeal lies from the Board to the Court of Appeal on a question of jurisdiction or on a question of law.
>
> **(2)** Leave to appeal may be obtained from a judge of the Court of Appeal only on an application made

(a) within 30 days from the day that the order, decision or direction sought to be appealed from was made, or

(b) within a further period of time as granted by the judge where the judge is of the opinion that the circumstances warrant the granting of that further period of time.

In addition, the AEUBA includes a privative clause which states that every action, order, ruling or decision of the Board is final and shall not be questioned, reviewed or restrained by any proceeding in the nature of an application for judicial review or otherwise in any court (s. 27).

25 The presence of a statutory right of appeal on questions of jurisdiction and law suggests a more searching standard of review and less deference to the Board on those questions (see *Pushpanathan*, at para. 30). However, the presence of the privative clause and right to appeal are not decisive, and one must proceed with the examination of the nature of the question to be determined and the relative expertise of the tribunal in those particular matters.

26 Second, as observed by the Court of Appeal, no one disputes the fact that the Board is a specialized body with a high level of expertise regarding Alberta's energy resources and utilities (see, e.g., *Consumers' Gas Co. v. Ontario (Energy Board)*, [2001] O.J. No. 5024 (QL), (Div. Ct.), at para. 2 ; *Coalition of Citizens Impacted by the Caroline Shell Plant v. Alberta (Energy Utilities Board)* (1996), 41 Alta. L.R. (3d) 374 (C.A.), at para. 14. In fact, the Board is a permanent tribunal with a long-term regulatory relationship with the regulated utilities.

27 Nevertheless, the Court is concerned not with the general expertise of the administrative decision maker, but with its expertise in relation to the specific nature of the issue before it. Consequently, while normally one would have assumed that the Board's expertise is far greater than that of a court, the nature of the problem at bar, to adopt the language of the Court of Appeal (para. 35), "neutralizes" this deference. As I will elaborate below, the expertise of the Board is not engaged when deciding the scope of its powers.

28 Third, the present case is governed by three pieces of legislation: the PUBA, the GUA and the AEUBA. These statutes give the Board a mandate to safeguard the public interest in the nature and quality of the service provided to the community by public utilities: *Atco Ltd. v. Calgary Power Ltd.*, [1982] 2 S.C.R. 557, at p. 576; *Dome Petroleum Ltd. v. Public Utilities Board (Alberta)* (1976), 2 A.R. 453 (C.A.), at paras. 20-22, aff'd [1977] 2 S.C.R. 822. The legislative framework at hand has as its main purpose the proper regulation of a gas utility in the public interest, more specifically the regulation of a monopoly in the public interest with its primary tool being rate setting, as I will explain later.

29 The particular provision at issue, s. 26(2)(d)(i) of the GUA, which requires a utility to obtain the approval of the regulator before it sells an asset, serves to protect the customers from adverse results brought about by any of the utility's transactions by ensuring that the economic benefits to customers are enhanced (MacAvoy and Sidak, at pp. 234-36).

30 While at first blush the purposes of the relevant statutes and of the Board can be conceived as a delicate balancing between different constituencies, i.e., the utility and the customer, and therefore entail determinations which are polycentric (*Pushpanathan*, at para. 36), the interpretation of the enabling statutes and the particular provisions under review (s. 26(2)(d) GUA and s. 15(3)(d) AEUBA) is not a polycentric question, contrary to the conclusion of the Court of Appeal. It is an inquiry into whether a proper construction of the enabling statutes gives the Board jurisdiction to allocate the profits realized from the sale of an asset. The Board was not created with the main purpose of interpreting the AEUBA, the GUA or the PUBA in the abstract, where no policy consideration is at issue, but rather to ensure that utility rates are always just and reasonable (see *Atco Ltd.*, at p. 576). In the case at bar, this protective role does not come into play. Hence, this factor points to a less deferential standard of review.

31 Fourth, the nature of the problem underlying each issue is different. The parties are in essence asking the Court to answer two questions (as I have set out above), the first of which is to determine whether the power to dispose of the proceeds of sale falls within the Board's statutory mandate. The Board, in its decision, determined that it had the power to allocate a portion of the proceeds of a sale of utility assets to the ratepayers; it based its decision on its statutory powers, the equitable principles rooted in the "regulatory compact" (see para. 63 of these reasons) and previous practice. This question is undoubtedly one of law and jurisdiction. The Board would arguably have no greater expertise with regard to this issue than the courts. A court is called upon to interpret provisions that have no technical aspect, in contrast with the provision disputed in *Barrie Public Utilities v. Canadian Cable Television Assn.*, [2003] 1 S.C.R. 476, 2003 SCC 28, at para. 86. The interpretation of general concepts such as "public interest" and "conditions" (as found in s. 15(3)(d) of the AEUBA) is not foreign to courts and is not derived from an area where the tribunal has been held to have greater expertise than the courts. The second question is whether the method and actual allocation in this case were reasonable. To resolve this issue, one must consider case law, policy justifications and the practice of other boards, as well as the details of the particular allocation in this case. The issue here is most likely characterized as one of mixed fact and law.

32 In light of the four factors, I conclude that each question requires a distinct standard of review. To determine the Board's power to allocate proceeds from a sale of utility assets suggests a standard of review of correctness. As expressed by the Court of Appeal, the focus of this inquiry remains on the particular provisions being invoked and interpreted by the tribunal (s. 26(2)(d) of the GUA and s. 15(3)(d) of the AEUBA) and "goes to jurisdiction" (*Pushpanathan*, at para. 28). Moreover, keeping in mind all the factors discussed, the generality of the proposition will be an additional factor in favour of the imposition of a correctness standard, as I stated in *Pushpanathan*, at para. 38:

> ... the broader the propositions asserted, and the further the implications of such decisions stray from the core expertise of the tribunal, the less likelihood that deference will be shown. Without an implied or express legislative intent to the contrary as manifested in the criteria above, legislatures should be assumed to have left highly generalized propositions of law to courts.

33 The second question regarding the Board's actual method used for the allocation of proceeds likely attracts a more deferential standard. On the one hand, the Board's expertise, particularly in this area, its broad mandate, the technical nature of the question and the general purposes of the legislation, all suggest a relatively high level of deference to the Board's decision. On the other hand, the absence of a privative clause on questions of jurisdiction and the reference to law needed to answer this question all suggest a less deferential standard of review which favours reasonableness. It is not necessary, however, for me to determine which specific standard would have applied here.

34 As will be shown in the analysis below, I am of the view that the Court of Appeal made no error of fact or law when it concluded that the Board acted beyond its jurisdiction by misapprehending its statutory and common law authority. However, the Court of Appeal erred when it did not go on to conclude that the Board has no jurisdiction to allocate <u>any</u> portion of the proceeds of sale of the property to ratepayers.

2.3 *Was the Board's Decision as to its Jurisdiction Correct?*

35 Administrative tribunals or agencies are statutory creations: they cannot exceed the powers that were granted to them by their enabling statute; they must "adhere to the confines of their statutory authority or 'jurisdiction'[; and t]hey cannot trespass in areas where the legislature has not assigned them authority": Mullan, at pp. 9-10 (see also S. Blake, *Administrative Law in Canada*, (3rd ed. 2001), at pp. 183-184).

36 In order to determine whether the Board's decision that it had the jurisdiction to allocate proceeds from the sale of a utility's asset was correct, I am required to interpret the legislative framework by which the Board derives its powers and actions.

2.3.1 <u>General Principles of Statutory Interpretation</u>

37 For a number of years now, the Court has adopted E. A. Driedger's modern approach as the method to follow for statutory interpretation (*Construction of Statutes* (2nd ed. 1983), at p. 87):

> Today there is only one principle or approach, namely, the words of an Act are to be read in their entire context and in their grammatical and ordinary sense harmoniously with the scheme of the Act, the object of the Act, and the intention of Parliament.

(See, e.g., see *Rizzo & Rizzo Shoes Ltd. (Re)*, [1998] 1 S.C.R. 27, at para. 21; *Bell ExpressVu Limited Partnership v. Rex*, [2002] 2 S.C.R. 559, 2002 SCC 42, at para. 26; *H.L. v. Canada (Attorney General)*, [2005] 1 S.C.R. 401, 2005 SCC 25, at paras. 186-87; *Marche v. Halifax Insurance Co.*, [2005] 1 S.C.R. 47, 2005 SCC 6, at para. 54; *Barrie Public Utilities*, at paras. 20 and 86; *Contino v. Leonelli-Contino*, 2005 SCC 63, at para. 19.)

38 But more specifically in the area of administrative law, tribunals and boards obtain their jurisdiction over matters from two sources: 1) express grants of jurisdiction under various statutes (explicit powers); and 2) the common law, by application of the doctrine of jurisdiction by necessary implication (implicit powers) (see also D. M. Brown, *Energy Regulation in Ontario* (loose-leaf ed.), at p. 2-15).

39 The City submits that it is both implicit and explicit within the express jurisdiction that has been conferred upon the Board to approve or refuse to approve the sale of utility assets, that the Board can determine how to allocate the proceeds of the sale in this case. ATCO retorts that not only is such a power absent from the explicit language of the legislation, but it cannot be "implied" from the statutory regime as necessarily incidental to the explicit powers. I agree with ATCO's submissions and will elaborate in this regard.

2.3.2 Explicit Powers: Grammatical and Ordinary Meaning

40 As a preliminary submission, the City argues that given that ATCO applied to the Board for approval of both the sale transaction and the disposition of the proceeds of sale, this suggests that ATCO recognized that the Board has authority to allocate the proceeds as a condition of a proposed sale. This argument does not hold any weight in my view. First, the application for approval cannot be considered on its own an admission by ATCO of the jurisdiction of the Board. In any event, an admission of this nature would not have any bearing on the applicable law. Moreover, knowing that in the past the Board had decided that it had jurisdiction to allocate the proceeds of a sale of assets and had acted on this power, one can assume that ATCO was asking for the approval of the disposition of the proceeds should the Board not accept their argument on jurisdiction. In fact, a review of past Board decisions on the approval of sales shows that utility companies have constantly challenged the Board's jurisdiction to allocate the net gain on the sale of assets (see, e.g., *TransAlta Utilities Corp.*, Alta. E.U.B. Decision 2000-41; *ATCO Gas-North, A Division of ATCO Gas and Pipelines Ltd.*, Alta. E.U.B. Decision 2001-65; *Alberta Government Telephones* (1984), Alta. P.U.B. Decision No. E84081; *TransAlta Utilities Corp.* (1984), Alta. P.U.B. Decision No. E84116; *TransAlta Utilities Corp. (Re)*, [2002] A.E.U.B.D. No. 30 (QL); *ATCO Electric Ltd. (Re)*, [2003] A.E.U.B.D. No. 92 (QL)).

41 The starting point of the analysis requires that the Court examine the ordinary meaning of the sections at the centre of the dispute, s. 26(2)(d)(i) of the GUA, ss. 15(1) and (3)(d) of the AEUBA and s. 37 of the PUBA. For ease of reference, I reproduce these provisions:

> GUA
>
> **26.** ...
>
> **(2)** No owner of a gas utility designated under subsection (1) shall
>
> ...
>
> (d) without the approval of the Board,

(i) sell, lease, mortgage or otherwise dispose of or encumber its property, franchises, privileges or rights, or any part of it or them

...

and a sale, lease, mortgage, disposition, encumbrance, merger or consolidation made in contravention of this clause is void, but nothing in this clause shall be construed to prevent in any way the sale, lease, mortgage, disposition, encumbrance, merger or consolidation of any of the property of an owner of a gas utility designated under subsection (1) in the ordinary course of the owner's business.

AEUBA

15(1) For the purposes of carrying out its functions, the Board has all the powers, rights and privileges of the ERCB [Energy Resources Conservation Board] and the PUB [Public Utilities Board] that are granted or provided for by any enactment or by law.

...

(3) Without restricting subsection (1), the Board may do all or any of the following:

...

(d) with respect to an order made by the Board, the ERCB or the PUB in respect of matters referred to in clauses (a) to (c), make any further order and impose any additional conditions that the Board considers necessary in the public interest;

...

PUBA

37 In matters within its jurisdiction the Board may order and require any person or local authority to do forthwith or within or at a specified time and in any manner prescribed by the Board, so far as it is not inconsistent with this Act or any other Act conferring jurisdiction, any act, matter or thing that the person or local authority is or may be required to do under this Act or under any other general or special Act, and may forbid the doing or continuing of any act, matter or thing that is in contravention of any such Act or of any regulation, rule, order or direction of the Board.

42 Some of the above provisions are duplicated in the other two statutes (see, e.g., PUBA, ss. 85(1) and 101(2)(d)(i); GUA, s. 22(1); see Appendix).

43 There is no dispute that s. 26(2) of the GUA contains a prohibition against, among other things, the owner of a utility selling, leasing, mortgaging or otherwise disposing of its property outside of the ordinary course of business without the approval of the Board. As submitted by ATCO, the power conferred is to approve without more. There is no mention in s. 26 of the grounds for granting or denying approval or of the ability to grant conditional approval, let alone the power of the Board to allocate the net profit of an asset sale. I would note in passing that this power is sufficient to alleviate the fear expressed by the Board that the utility might be tempted to sell assets on which it might realize a large profit to the detriment of ratepayers if it could reap the benefits of the sale.

44 It is interesting to note that s. 26(2) does not apply to all types of sales (and leases, mortgages, dispositions, encumbrances, mergers or consolidations). It excludes sales in the ordinary course of the owner's business. If the statutory scheme was such that the Board had the power to allocate the proceeds of the sale of utility assets, as argued here, s. 26(2) would naturally apply to all sales of assets or, at a minimum, exempt only those sales below a certain value. It is apparent that allocation of sale proceeds to customers is not one of its purposes. In fact, s. 26(2) can only have limited, if any, application to non-utility assets not related to utility function (especially when the sale has passed the "no-harm" test). The provision can only be meant to ensure that the asset in question is indeed non-utility, so that its loss does not impair the utility function or quality.

45 Therefore, a simple reading of s. 26(2) of the GUA does permit one to conclude that the Board does not have the power to allocate the proceeds of an asset sale.

46 The City does not limit its arguments to s. 26(2); it also submits that the AEUBA, pursuant to s. 15(3), is an express grant of jurisdiction because it authorizes the Board to impose any condition to any order so long as the condition is necessary in the public interest. In addition, it relies on the general power in s. 37 of the PUBA for the proposition that the Board may, in any matter within its jurisdiction, make any order pertaining to that matter that is not inconsistent with any applicable statute. The intended meaning of these two provisions, however, is lost when the provisions are simply read in isolation as proposed by the City: R. Sullivan, *Sullivan and Driedger on the Construction of Statutes* (4th ed. 2002), at p. 21; *Canadian Pacific Air Lines Ltd. v. Canadian Air Line Pilots Assn.*, [1993] 3 S.C.R. 724, at p. 735; *Marche*, at paras. 59-60; *Bristol-Myers Squibb Co. v. Canada (Attorney General)*, [2005] 1 S.C.R. 533, 2005 SCC 26, at para. 105). These provisions on their own are vague and open-ended. It would be absurd to allow the Board an unfettered discretion to attach any condition it wishes to an order it makes. Furthermore, the concept of "public interest" found in s. 15(3) is very wide and elastic; the Board cannot be given total discretion over its limitations.

47 While I would conclude that the legislation is silent as to the Board's power to deal with sale proceeds after the initial stage in the statutory interpretation analysis, because the provisions can nevertheless be said to reveal some ambiguity and incoherence, I will pursue the inquiry further.

48 This Court has stated on numerous occasions that the grammatical and ordinary sense of a section is not determinative and does not constitute the end of the inquiry. The Court is obliged to consider the total context of the provisions to be interpreted, no matter how plain the disposition may seem upon initial reading (see *Chieu v. Canada (Minister of Citizenship and Immigration)*, [2002] 1 S.C.R. 84, 2002 SCC 3, at para. 34; Sullivan, at pp. 20-21). I will therefore proceed to examine the purpose and scheme of the legislation, the legislative intent and the relevant legal norms.

2.3.3 <u>Implicit Powers: Entire Context</u>

49 The provisions at issue are found in statutes which are themselves components of a larger statutory scheme which cannot be ignored:

> As the product of a rational and logical legislature, the statute is considered to form a system. Every component contributes to the meaning as a whole, and the whole gives meaning to its parts: "each legal provision should be considered in relation to other provisions, as parts of a whole" ...
>
> (P.-A. Côté, *The Interpretation of Legislation in Canada* (3rd ed. 2000), at p. 308)

As in any statutory interpretation exercise, when determining the powers of an administrative body, courts need to examine the context that colours the words and the legislative scheme. The ultimate goal is to discover the clear intent of the legislature and the true purpose of the statute while preserving the harmony, coherence and consistency of the legislative scheme (*Bell ExpressVu*, at para. 27; see also *Interpretation Act*, R.S.A. 2000, c. I-8, s. 10 (in Appendix)).

"[S]tatutory interpretation is the art of finding the legislative spirit embodied in enactments": *Bristol-Myers Squibb Co.*, at para. 102.

50 Consequently, a grant of authority to exercise a discretion as found in s. 15(3) of the AEUBA and s. 37 of the PUBA does not confer unlimited discretion to the Board. As submitted by ATCO, the Board's discretion is to be exercised within the confines of the statutory regime and principles generally applicable to regulatory matters, for which the legislature is assumed to have had regard in passing that legislation (see Sullivan, at pp. 154-55). In the same vein, it is useful to refer to the following passage from *Bell Canada v. Canada (Canadian Radio-Television and Telecommunications Commission)*, [1989] 1 S.C.R. 1722, at p. 1756:

> The powers of any administrative tribunal must of course be stated in its enabling statute but they may also exist by necessary implication from the wording of the act, its structure and its purpose. Although courts must refrain from unduly broadening the powers of such regulatory authorities through judicial law-making, they must also avoid sterilizing these powers through overly technical interpretations of enabling statutes.

51 The mandate of this Court is to determine and apply the intention of the legislature (*Bell ExpressVu*, at para. 62) without crossing the line between judicial interpretation and legislative drafting (see *R. v. McIntosh*, [1995] 1 S.C.R. 686, at para. 26; *Bristol-Myers Squibb Co.*, at para. 174). That being said, this rule allows for the application of the "doctrine of jurisdiction by necessary implication"; the powers conferred by an enabling statute are construed to include not only those expressly granted but also, by implication, all powers which are practically necessary for the accomplishment of the object intended to be secured by the statutory regime created by the legislature (see Brown, at p. 2-16.2; *Bell Canada*, at p. 1756). Canadian courts have in the past applied the doctrine to ensure that administrative bodies have the necessary jurisdiction to accomplish their statutory mandate:

> When legislation attempts to create a comprehensive regulatory framework, the tribunal must have the powers which by practical necessity and necessary implication flow from the regulatory authority explicitly conferred upon it.

Re Dow Chemical Canada Inc. and Union Gas Ltd. (1982), 141 D.L.R. (3d) 641 (Ont. H.C.J.), at pp. 658-59, aff'd (1983), 42 O.R. (2d) 731 (C.A.) (see also *Interprovincial Pipe Line Ltd. v. National Energy Board*, [1978] 1 F.C. 601 (C.A.); *Canadian Broadcasting League v. Canadian Radio-television and Telecommunications Commission*, [1983] 1 F.C. 182 (C.A.), aff'd. [1985] 1 S.C.R. 174).

52 I understand the City's arguments to be as follows : 1) the customers acquire a right to the property of the owner of the utility when they pay for the service and are therefore entitled to a return on the profits made at the time of the sale of the property; and 2) the Board has, by necessity, because of its jurisdiction to approve or refuse to approve the sale of utility assets, the power to allocate the proceeds of the sale as a condition of its order. The doctrine of jurisdiction by necessary implication is at the heart of the City's second argument. I cannot accept either of these arguments which are, in my view, diametrically contrary to the state of the law. This is revealed when we scrutinize the entire context which I will now endeavour to do.

53 After a brief review of a few historical facts, I will probe into the main function of the Board, rate setting, and I will then explore the incidental powers which can be derived from the context.

2.3.3.1 *Historical Background and Broader Context*

54 The history of public utilities regulation in Alberta originated with the creation in 1915 of the Board of Public Utility Commissioners by *The Public Utilities Act*, S.A. 1915, c. 6. This statute was based on similar American legislation: H. R. Milner, "Public Utility Rate Control in Alberta" (1930), 8 *Can. Bar Rev.* 101, at p. 101. While the American jurisprudence and texts in this area should be considered with caution given that Canada and the United States have very different political and constitutional-legal regimes, they do shed some light on the issue.

55 Pursuant to *The Public Utilities Act*, the first public utility board was established as a three-member tribunal to provide general supervision of all public utilities (s. 21), to investigate rates (s. 23), to make orders regarding equipment (s. 24), and to require every public utility to file with it complete schedules of rates (s. 23). Of interest for our purposes, the 1915 statute also required public utilities to obtain the approval of the Board of Public Utility Commissioners before selling any property when outside the ordinary course of their business (s. 29(g)).

56 The Alberta Energy and Utilities Board was created in February 1995 by the amalgamation of the Energy Resources Conservation Board and the Public Utilities Board (see Canadian Institute of Resources Law, *Canada Energy Law Service: Alberta* (loose-leaf ed.), at p. 30-3101). Since then, all matters under the jurisdiction of the Energy Resources Conservation Board and the Public Utilities Board have been handled by the Alberta Energy and Utilities Board and are within its exclusive jurisdiction. The Board has all of the powers, rights and privileges of its two predecessor boards (AEUBA, ss. 13, 15(1); GUA, s. 59).

57 In addition to the powers found in the 1915 statute, which have remained virtually the same in the present PUBA , the Board now benefits from the following express powers to:

1. make an order respecting the improvement of the service or commodity (PUBA, s. 80(b))
2. approve the issue by the public utility of shares, stocks, bonds and other evidences of indebtedness (GUA, s. 26(2)(a)); PUBA, s. 101(2)(a));
3. approve the lease, mortgage, disposition or encumbrance of the public utility's property, franchises, privileges or rights (GUA, s. 26(2)(d)(i); PUBA, s. 101(2)(d)(i));
4. approve the merger or consolidation of the public utility's property, franchises, privileges or rights (GUA, s. 26(2)(d)(ii); PUBA, s. 101(2)(d)(ii)); and
5. authorize the sale or permit to be made on the public utility's book a transfer of any share of its capital stock to a corporation that would result in the vesting in that corporation of more than 50% of the outstanding capital stock of the owner of the public utility (GUA, 27(1); PUBA, s. 102(1)).

58 It goes without saying that public utilities are very limited in the actions they can take, as evidenced from the above list. Nowhere is there a mention of the authority to allocate proceeds from a sale or the discretion of the Board to interfere with ownership rights.

59 Even in 1995 when the legislature decided to form the Alberta Energy and Utilities Board, it did not see fit to modify the PUBA or the GUA to provide the new Board with the power to allocate the proceeds of a sale even though the controversy surrounding this issue was full-blown (see, e.g., *Alberta Government Telephones* (1984), Alta. P.U.B. Decision No. E84081; *TransAlta Utilities Corp.* (1984), Alta. P.U.B. Decision No. E84116). It is a well-established principle that the legislature is presumed to have a mastery of existing law, both common law and statute law (see Sullivan, at pp. 154-55). It is also presumed to have known all of the circumstances surrounding the adoption of new legislation.

60 Although the Board may seem to possess a variety of powers and functions, it is manifest from a reading of the AEUBA, the PUBA and the GUA that the principal function of the Board in respect of public utilities is the determination of rates. Its power to supervise the finances of these companies and their operations, although wide, is in practice incidental to fixing rates (see Milner, at p. 102; Brown, at p. 2-16.6). Estey J., speaking for the majority of this Court in *Atco Ltd.*, at p. 576, echoed this view when he said:

> It is evident from the powers accorded to the Board by the legislature in both statutes mentioned above that the legislature has given the Board a mandate of the widest proportions to safeguard the public interest in the nature and quality of the service provided to the community by the public utilities. Such an extensive regulatory pattern must, for its effectiveness, include the right to control the combination or, as the legislature says, "the union" of existing systems and

> facilities. This no doubt has a direct relationship with the rate-fixing function which ranks high in the authority and functions assigned to the Board [Emphasis added.]

In fact, even the Board itself, on its website (http://www.eub.gov.ab.ca/BBS/eubinfo/default.htm), describes its functions as follows:

> We regulate the safe, responsible, and efficient development of Alberta's energy resources: oil, natural gas, oil sands, coal, and electrical energy; and the pipelines and transmission lines to move the resources to market. On the utilities side, we regulate rates and terms of service of investor-owned natural gas, electric, and water utility services, as well as the major intra-Alberta gas transmission system, to ensure that customers receive safe and reliable service at just and reasonable rates. [Emphasis added.]

61 The process by which the Board sets the rates is therefore central and deserves some attention in order to ascertain the validity of the City's first argument.

2.3.3.2 *Rate Setting*

62 Rate regulation serves several aims - sustainability, equity and efficiency - which underlie the reasoning as to how rates are fixed:

> ... the regulated company must be able to finance its operations, and any required investment, so that it can continue to operate in the future. Equity is related to the distribution of welfare among members of society. The objective of sustainability already implies that shareholders should not receive "too low" a return (and defines this in terms of the reward necessary to ensure continued investment in the utility), while equity implies that their returns should not be "too high".
>
> (R. Green and M. Rodriguez Pardina, *Resetting Price Controls for Privatized Utilities: A Manual for Regulators* (1999), at p. 5)

63 These goals have resulted in an economic and social arrangement dubbed the "regulatory compact", which ensures that all customers have access to the utility at a fair price - nothing more. As I will further explain, it does not transfer onto the customers any property right. Under the regulatory compact, the regulated utilities are given exclusive rights to sell their services within a specific area at rates that will provide companies the opportunity to earn a fair return for their investors. In return for this right of exclusivity, utilities assume a duty to adequately and reliably serve all customers in their determined territories, and are required to have their rates and certain operations regulated (see Black, at pp. 356-57; Milner, at p. 101; *Atco*, at p. 576; *Northwestern Utilities Ltd. v. City of Edmonton*, [1929] S.C.R. 186, at pp. 192-93 (hereinafter "*Northwestern 1929*")).

64 Therefore, when interpreting the broad powers of the Board, one cannot ignore this well-balanced regulatory arrangement which serves as a backdrop for contextual interpretation. The object of the statutes is to protect both the customer and the investor (Milner, at p. 101). The arrangement does not, however, cancel the private nature of the utility. In essence, the Board is responsible for maintaining a tariff that enhances the economic benefits to consumers and investors of the utility.

65 The Board derives its power to set rates from both the GUA (ss. 16, 17 and 36 to 45) and the PUBA (ss. 89 to 95). The Board is mandated to fix "just and reasonable ... rates" (PUBA, s. 89(a), GUA, s. 36(a)). In the establishment of these rates, the Board is directed to "determine a rate base for the property of the owner" and "fix a fair return on the rate base" (GUA, s. 37(1)). This Court, in *Northwestern Utilities Ltd. v. City of Edmonton*, [1979] 1 S.C.R. 684, at p. 691 (hereinafter "*Northwestern 1979*"), adopted the following description of the process:

> The PUB approves or fixes utility rates which are estimated to cover expenses plus yield the utility a fair return or profit. This function is generally performed in two phases. In Phase I the PUB determines the rate base, that is the amount of money which has been invested by the company in the property, plant and equipment plus an allowance for necessary working capital all of which must be determined as being necessary to provide the utility service. The revenue required to pay all reasonable operating expenses plus provide a fair return to the utility on its rate base is also determined in Phase I. The total of the operating expenses plus the return is called the revenue requirement. In Phase II rates are set, which, under normal temperature conditions are expected to produce the estimates of "forecast revenue requirement". These rates will remain in effect until changed as the result of a further application or complaint or the Board's initiative. Also in Phase II existing interim rates may be confirmed or reduced and if reduced a refund is ordered.

(See also *Re Gas Utilities Act and Public Utilities Board Act* (1984), Alta. P.U.B. Decision No. E84113, at p. 23; *Re Union Gas Ltd. and Ontario Energy Board* (1983), 1 D.L.R. (4th) 698 (Ont. Div. Ct.), at pp. 701-702.)

66 Consequently, when determining the rate base, the Board is to give due consideration (GUA, s. 37(2)):

> (a) to the cost of the property when first devoted to public use and to prudent acquisition cost to the owner of the gas utility, less depreciation, amortization or depletion in respect of each, and
> (b) to necessary working capital.

67 The fact that the utility is given the opportunity to make a profit on its services and a fair return on its investment in its assets should not and cannot stop the utility from benefiting from the profits which follow the sale of assets. Neither is the utility protected from losses incurred from the sale of assets. In fact, the wording of the sections quoted above suggests that the ownership of the assets is clearly that of the utility; ownership of the asset and entitlement to profits or losses upon its realization are one and the same. The equity investor expects to receive the net revenues after all costs are paid, equal to the present value of original investment at the time of that investment. The disbursement of some portions of the residual amount of net revenue, by after-the-fact reallocation to rate-paying customers, undermines that investment process: MacAvoy and Sidak, at p. 244. In fact, speculation would accrue even more often should the public utility, through its shareholders, not be the one to benefit from the possibility of a profit, as investors would expect to receive a larger premium for their funds through the only means left available, the return on their original investment. In addition, they would be less willing to accept any risk.

68 Thus, can it be said, as alleged by the City, that the customers have a property interest in the utility? Absolutely not: that cannot be so, as it would mean that fundamental principles of corporate law would be distorted. Through the rates, the customers pay an amount for the regulated service that equals the cost of the service and the necessary resources. They do not by their payment implicitly purchase the asset from the utility's investors. The payment does not incorporate acquiring ownership or control of the utility's assets. The ratepayer covers the cost of using the service, not the holding cost of the assets themselves: "A utility's customers are not its owners, for they are not residual claimants": MacAvoy and Sidak, at p. 245 (see also p. 237). Ratepayers have made no investment. Shareholders have and they assume all risks as the residual claimants to the utility's profit. Customers have only "the risk of a price change resulting from any (authorized) change in the cost of service. This change is determined only periodically in a tariff review by the regulator" (MacAvoy and Sidak, p. 245).

69 In this regard, I agree with ATCO when it asserts in its factum, at para. 38:

> The property in question is as fully the private property of the owner of the utility as any other asset it owns. Deployment of the asset in utility service does not create or transfer any legal or equitable rights in that property for ratepayers. Absent any such interest, any taking such as

> ordered by the Board is confiscatory ...

Wittmann J.A., at the Court of Appeal, said it best when he stated:

> Consumers of utilities pay for a service, but by such payment, do not receive a proprietary right in the assets of the utility company. Where the calculated rates represent the fee for the service provided in the relevant period of time, ratepayers do not gain equitable or legal rights to non-depreciable assets when <u>they have paid only for the use of those assets</u>. [Emphasis added; para. 64.]

I fully adopt this conclusion. The Board misdirected itself by confusing the interests of the customers in obtaining safe and efficient utility service with an interest in the underlying assets owned only by the utility. While the utility has been compensated for the services provided, the customers have provided no compensation for receiving the benefits of the subject property. The argument that assets purchased are reflected in the rate base should not cloud the issue of determining who is the appropriate owner and risk bearer. Assets are indeed considered in rate setting, as a factor, and utilities cannot sell an asset used in the service to create a profit and thereby restrict the quality or increase the price of service. Despite the consideration of utility assets in the rate-setting process, shareholders are the ones solely affected when the actual profits or losses of such a sale are realized; the utility absorbs losses and gains, increases and decreases in the value of assets, based on economic conditions and occasional unexpected technical difficulties, but continues to provide certainty in service both with regard to price and quality. There can be a default risk affecting ratepayers, but this does not make ratepayers residual claimants. While I do not wish to unduly rely on American jurisprudence, I would note that the leading U.S. case on this point is *Duquesne Light Co. v. Barasch*, 488 U.S. 299 (1989), which relies on the same principle as was adopted in *Market St. Ry. Co. v. Railroad Commission of State of California*, 324 US 548 (1945).

70 Furthermore, one has to recognize that utilities are not Crown entities, fraternal societies or cooperatives, or mutual companies, although they have a "public interest" aspect which is to supply the public with a necessary service (in the present case, the provision of natural gas). The capital invested is not provided by the public purse or by the customers; it is injected into the business by private parties who expect as large a return on the capital invested in the enterprise as they would receive if they were investing in other securities possessing equal features of attractiveness, stability and certainty (see *Northwestern 1929*, at p. 192). This prospect will necessarily include any gain or loss that is made if the company divests itself of some of its assets, i.e., land, buildings, etc.

71 From my discussion above regarding the property interest, the Board was in no position to proceed with an implicit refund by allocating to ratepayers the profits from the asset sale because it considered ratepayers had paid excessive rates for services in the past. As such, the City's first argument must fail. The Board was seeking to rectify what it perceived as a historic over-compensation to the utility by ratepayers. There is no power granted in the various statutes for the Board to execute such a refund in respect of an erroneous perception of past over-compensation. It is well established throughout the various provinces that utilities boards do not have the authority to retroactively change rates (*Northwestern 1979*, at p. 691; *Re Coseka Resources Ltd. and Saratoga Processing Co.* (1981), 126 D.L.R. (3d) 705 (Alta. C.A.), at p. 715, leave to appeal refused, [1981] 2 S.C.R. vii; *Re Dow Chemical Canada Inc.* (C.A.), at pp. 734-35). But more importantly, it cannot even be said that there was over-compensation: the rate-setting process is a speculative procedure in which both the ratepayers and the shareholders jointly carry their share of the risk related to the business of the utility (see MacAvoy and Sidak, at pp. 238-39).

2.3.3.3 *The Power to Attach Conditions*

72 As its second argument, the City submits that the power to allocate the proceeds from the sale of the utility's assets is necessarily incidental to the express powers conferred on the Board by the AEUBA, the GUA and the PUBA. It argues that the Board must necessarily have the power to allocate sale proceeds as part of its discretionary power to approve or refuse to approve a sale of assets. It submits that this results from the fact that the Board is allowed to attach any condition to an order it makes approving such a sale. I disagree.

73 The City seems to assume that the doctrine of jurisdiction by necessary implication applies to "broadly drawn powers" as it does for "narrowly drawn powers"; this cannot be. The Ontario Energy Board in its decision in *Re Consumers' Gas Co.* (1987), E.B.R.O. 410-II/411-II/412-II, at para. 4.73, enumerated the circumstances when the doctrine of jurisdiction by necessary implication may be applied:

> 1. when the jurisdiction sought is necessary to accomplish the objects of the legislative scheme and is essential to the Board fulfilling its mandate;
> 2. when the enabling act fails to explicitly grant the power to accomplish the legislative objective;
> 3. when the mandate of the Board is sufficiently broad to suggest a legislative intention to implicitly confer jurisdiction;
> 4. when the jurisdiction sought is not one which the Board has dealt with through use of expressly granted powers, thereby showing an absence of necessity; and
> 5. when the legislature did not address its mind to the issue and decide against conferring the power to the Board. (See also Brown, at p. 2-16.3.)

74 In light of the above, it is clear that the doctrine of jurisdiction by necessary implication will be of less help in the case of broadly drawn powers than for narrowly drawn ones. Broadly drawn powers will necessarily be limited to only what is rationally related to the purpose of the regulatory framework. This is explained by Professor Sullivan, at p. 228:

> In practice, however, purposive analysis makes the powers conferred on administrative bodies almost infinitely elastic. Narrowly drawn powers can be understood to include "by necessary implication" all that is needed to enable the official or agency to achieve the purpose for which the power was granted. Conversely, broadly drawn powers are understood to include only what is rationally related to the purpose of the power. In this way the scope of the power expands or contracts as needed, in keeping with the purpose. [Emphasis added.]

75 In the case at bar, s. 15 of the AEUBA, which allows the Board to impose additional conditions when making an order, appears at first glance to be a power having infinitely elastic scope. However, in my opinion, the attempt by the City to use it to augment the powers of the Board in s. 26(2) of the GUA must fail. The Court must construe s. 15(3) of the AEUBA in accordance with the purpose of s. 26(2).

76 MacAvoy and Sidak, in their article, at pp. 234-36, suggest three broad reasons for the requirement that a sale must be approved by the Board:

> 1. It prevents the utility from degrading the quality, or reducing the quantity, of the regulated service so as to harm consumers;
> 2. It ensures that the utility maximizes the aggregate economic benefits of its operations, and not merely the benefits flowing to some interest group or stakeholder; and
> 3. It specifically seeks to prevent favoritism toward investors.

77 Consequently, in order to impute jurisdiction to a regulatory body to allocate proceeds of a sale, there must be evidence that the exercise of that power is a practical necessity for the regulatory body to accomplish the objects prescribed by the legislature, something which is absent in this case (see *National Energy Board Act (Can.) (Re)*, [1986] 3 F.C. 275 (C.A.)). In order to meet these three goals, it is not necessary for the Board to have control over which party should benefit from the sale proceeds. The public interest component cannot be said to be sufficient to impute to the Board the power to allocate all the profits pursuant to the sale of assets. In fact, it is not necessary for the Board in carrying out its mandate to order the utility to surrender the bulk of the proceeds from a sale of its property in order for that utility to obtain approval for a sale. The Board has other options within its jurisdiction which do not involve the appropriation of the sale proceeds, the most obvious one being to refuse to approve a sale that will, in the Board's view, affect the quality and/or quantity of the service offered by the utility or create additional operating costs for the future. This is not to say that the Board can never attach a condition to the approval of sale. For example, the Board could approve the sale of the assets on the condition that the utility company gives undertakings regarding the replacement of the assets and their profitability. It could also require as a condition that the utility reinvest part of the sale proceeds back into the company in order to maintain a modern operating system that achieves the optimal growth of the system.

78 In my view, allowing the Board to confiscate the net gain of the sale under the pretence of protecting rate-paying customers and acting in the "public interest" would be a serious misconception of the powers of the Board to approve a sale; to do so would completely disregard the economic rationale of rate setting, as I explained earlier in these reasons. Such an attempt by the Board to appropriate a utility's excess net revenues for ratepayers would be highly sophisticated opportunism and would, in the end, simply increase the utility's capital costs (MacAvoy and Sidak, at p. 246). At the risk of repeating myself, a public utility is first and foremost a private business venture which has as its goal the making of profits. This is not contrary to the legislative scheme, even though the regulatory compact modifies the normal principles of economics with various restrictions explicitly provided for in the various enabling statutes. None of the three statutes applicable here provides the Board with the power to allocate the proceeds of a sale and therefore affect the property interests of the public utility.

79 It is well established that potentially confiscatory legislative provision ought to be construed cautiously so as not to strip interested parties of their rights without the clear intention of the legislation (see Sullivan, at pp. 400-403; Côté, at pp. 482-86; *Pacific National Investments Ltd. v. Victoria (City)*, [2000] 2 S.C.R. 919, 2000 SCC 64, at para. 26; *Leiriao v. Val-Bélair (Town)*, [1991] 3 S.C.R. 349, at p. 357; *Hongkong Bank of Canada v. Wheeler Holdings Ltd.*, [1993] 1 S.C.R. 167, at p. 197). Not only is the authority to attach a condition to allocate the proceeds of a sale to a particular party unnecessary for the Board to accomplish its role, but deciding otherwise would lead to the conclusion that a broadly drawn power can be interpreted so as to encroach on the economic freedom of the utility, depriving it of its rights. This would go against the above principles of interpretation.

80 If the Alberta legislature wishes to confer on ratepayers the economic benefits resulting from the sale of utility assets, it can expressly provide for this in the legislation, as was done by some states in the United States (e.g., Connecticut).

2.4 *Other Considerations*

81 Under the regulatory compact, customers are protected through the rate-setting process, under which the Board is required to make a well-balanced determination. The record shows that the City did not submit to the Board a general rate review application in response to ATCO's application requesting approval for the sale of the property at issue in this case. Nonetheless, if it chose to do so, this would not have stopped the Board, on its own initiative, from convening a hearing of the interested parties in order to modify and fix just and reasonable rates to give due consideration to any new economic data anticipated as a result of the sale (PUBA, s. 89(a); GUA, ss. 24, 36(a), 37(3), 40) (see Appendix).

2.5 *If Jurisdiction Had Been Found, Was the Board's Allocation Reasonable?*

82 In light of my conclusion with regard to jurisdiction, it is not necessary to determine whether the Board's exercise of discretion by allocating the sale proceeds as it did was reasonable. Nonetheless, given the reasons of my colleague Binnie J., I will address the issue very briefly. Had I not concluded that the Board lacked jurisdiction, my disposition of this case would have been the same, as I do not believe the Board met a reasonable standard when it exercised its power.

83 I am not certain how one could conclude that the Board's allocation was reasonable when it wrongly assumed that ratepayers had acquired a proprietary interest in the utility's assets because assets were a factor in the rate-setting process, and, moreover, when it explicitly concluded that no harm would ensue to customers from the sale of the asset.

In my opinion, when reviewing the substance of the Board's decision, a court must conduct a two-step analysis: first, it must determine whether the order was warranted given the role of the Board to protect the customers, (i.e., was the order necessary in the public interest?); and second, if the first question is answered in the affirmative, a court must then examine the validity of the Board's application of the *TransAlta Formula* (see para. 12 of these reasons), which refers to the difference between net book value and original cost, on the one hand, and appreciation in the value of the asset on the other. For the purposes of this analysis, I view the second step as a mathematical calculation and nothing more. I do not believe it provides the criteria which guides the Board to determine if it should allocate part of the sale proceeds to ratepayers. Rather, it merely guides the Board on what to allocate and how to allocate it (if it should do so in the first place). It is also interesting to note that there is no discussion of the fact that the book value used in the calculation must be referable solely to the financial statements of the utility.

84 In my view, as I have already stated, the power of the Board to allocate proceeds does not even arise in this case. Even by the Board's own reasoning, it should only exercise its discretion to act in the public interest when customers would be harmed or would face some risk of harm. But the Board was clear: there was no harm or risk of harm in the present situation (Decision 2002-037; para. 54):

> With the continuation of the same level of service at other locations and the acceptance by customers regarding the relocation, the Board is convinced there should be no impact on the level of service to customers as a result of the Sale. In any event, the Board considers that the service level to customers is a matter that can be addressed and remedied in a future proceeding if necessary.

After declaring that the customers would not, on balance, be harmed, the Board maintained that, on the basis of the evidence filed, there appeared to be a cost savings to the customers. There was no legitimate customer interest which could or needed to be protected by denying approval of the sale, or by making approval conditional on a particular allocation of the proceeds. Even if the Board had found a possible adverse effect arising from the sale, how could it allocate proceeds now based on an unquantified future potential loss? Moreover, in the absence of any factual basis to support it, I am also concerned with the presumption of bad faith on the part of ATCO that appears to underlie the Board's determination to protect the public from some possible future menace. In any case, as mentioned earlier in these reasons, this determination to protect the public interest is also difficult to reconcile with the actual power of the Board to prevent harm to ratepayers from occurring by simply refusing to approve the sale of a utility's asset. To that, I would add that the Board has considerable discretion in the setting of future rates in order to protect the public interest, as I have already stated.

85 In consequence, I am of the view that, in the present case, the Board did not identify any public interest which required protection and there was, therefore, nothing to trigger the exercise of the discretion to allocate the proceeds of sale. Hence, notwithstanding my conclusion on the first issue regarding the Board's jurisdiction, I would conclude that the Board's decision to exercise its discretion to protect the public interest did not meet a reasonable standard.

3. Conclusion

86 This Court's role in this case has been one of interpreting the enabling statutes using the appropriate interpretive tools, i.e. context, legislative intention and objective. Going further than required by reading in unnecessary powers of an administrative agency under the guise of statutory interpretation is not consistent with the rules of statutory interpretation. It is particularly dangerous to adopt such an approach when property rights are at stake.

87 The Board did not have the jurisdiction to allocate the proceeds of the sale of the utility's asset; its decision did not meet the correctness standard. Thus, I would dismiss the City's appeal and allow ATCO's cross-appeal, both with costs. I would also set aside the Board's decision and refer the matter back to the Board to approve the sale of the property belonging to ATCO, recognizing that the proceeds of the sale belong to ATCO.

The reasons of McLachlin C.J. and Binnie and Fish JJ. were delivered by

88 BINNIE J.:-- The respondent ATCO Gas and Pipelines Ltd. ("ATCO") is part of a large entrepreneurial company that directly and through various subsidiaries operates both regulated businesses and unregulated businesses. The Alberta Energy and Utilities Board (the "Board") believes it not to be in the public interest to encourage utility companies to mix together the two types of undertakings. In particular, the Board has adopted policies to discourage utilities from using their regulated businesses as a platform to engage in land speculation to increase their return on investment outside the regulatory framework. By awarding part of the profit to the utility (and its shareholders), the Board rewards utilities for diligence in divesting themselves of assets that are no longer productive, or that could be more productively employed elsewhere. However, by crediting part of the profit on the sale of such property to the utility's rate base (i.e. as a set-off to other costs), the Board seeks to dampen any incentive for utilities to skew decisions in their regulated business to favour such profit taking unduly. Such a balance, in the Board's view, is necessary in the interest of the public which allows ATCO to operate its utility business as a monopoly. In pursuit of this balance, the Board approved ATCO's application to sell land and warehousing facilities in downtown Calgary, but denied ATCO's application to keep for its shareholders the entire profit resulting from appreciation in the value of the land, whose cost of acquisition had formed part of the rate base on which gas rates had been calculated since 1922. The Board ordered the profit on the sale to be allocated one third to ATCO and two thirds as a credit to its cost base, thereby helping keep utility rates down, and to that extent benefiting ratepayers.

89 I have read with interest the reasons of my colleague Bastarache J. but, with respect, I do not agree with his conclusion. As will be seen, the Board has authority under s. 15(3) of the *Alberta Energy and Utilities Board Act*, R.S.A. 2000, c. A-17 ("AEUBA") to impose on the sale "any additional conditions that the Board considers necessary in the public interest". Whether or not the conditions of approval imposed by the Board were necessary in the public interest was for the Board to decide. The Alberta Court of Appeal overruled the Board but, with respect, the Board is in a better position to assess necessity in this field for the protection of the public interest than either that court or this Court. I would allow the appeal and restore the Board's decision.

I. Analysis

90 ATCO's argument boils down to the proposition announced at the outset of its factum:

> In the absence of any property right or interest and of any harm to the customers arising from the withdrawal from utility service, there was no proper ground for reaching into the pocket of the utility. In essence this case is about property rights.
>
> (Respondent's factum, para. 2)

91 For the reasons which follow I do not believe the case is about property rights. ATCO chose to make its investment in a regulated industry. The return on investment in the regulated gas industry is fixed by the Board, not the free market. In my view, the essential issue is whether the Alberta Court of Appeal was justified in limiting what the Board is allowed to "conside[r] necessary in the public interest".

A. *The Board's Statutory Authority*

92 The first question is one of jurisdiction. What gives the Board the authority to make the order ATCO complains about? The Board's answer is threefold. Section 22(1) of the *Gas Utilities Act*, R.S.A. 2000, c. G-5 ("GUA") provides in part that "[t]he Board shall exercise a general supervision over all gas utilities, and the owners of them ...". This, the Board says, gives it a broad jurisdiction to set policies that go beyond its specific powers in relation to specific applications, such as rate setting. Of more immediate pertinence, s. 26(2)(d)(i) of the same Act prohibits the regulated utility from selling, leasing or otherwise encumbering any of its property without the Board's approval. (To the same effect, see s. 101(2)(d)(i) of the *Public Utilities Board Act*, R.S.A. 2000, c. P-45.) It is common ground that this restraint on alienation of property applies to the proposed sale of ATCO's land and warehouse facilities in downtown Calgary, and that the Board could, in appropriate circumstances, simply have denied ATCO's application for approval of the sale. However, the Board was of the view to allow the sale subject to conditions. The Board ruled that the greater power (i.e. to deny the sale) must include the lesser (i.e. to allow the sale, subject to conditions) (Decision 2002-037, [2002] A.E.U.B.D. No. 52 (QL), para. 47).

> In appropriate circumstances, the Board clearly has the power to prevent a utility from disposing of its property. In the Board's view it also follows that the Board can approve a disposition subject to appropriate conditions to protect customer interests.

There is no need to rely on any such implicit power to impose conditions, however. As stated, the Board's explicit power to impose conditions is found in s. 15(3) of the AEUBA, which authorizes the Board to "make any further order and impose any additional conditions that the Board considers necessary in the public interest". In *Atco Ltd. v. Calgary Power Ltd.*, [1982] 2 S.C.R. 557, at p. 576, Estey, J., for the majority, stated:

> It is evident from the powers accorded to the Board by the legislature in both statutes mentioned above that the legislature has given the Board <u>a mandate of the widest proportions to safeguard the public interest</u> in the nature and quality of the service provided to the community by the public utilities. [Emphasis added.]

The legislature says in s. 15(3) that the conditions are to be what <u>the Board</u> considers necessary. Of course, the discretionary power to impose conditions thus granted is not unlimited. It must be exercised in good faith for its intended purpose: *C.U.P.E. v. Ontario (Minister of Labour)*, [2003] 1 S.C.R. 539, 2003 SCC 29. ATCO says the Board overstepped even these generous limits. In ATCO's submission:

> Deployment of the asset in utility service does not create or transfer any legal or equitable rights in that property for ratepayers. Absent any such interest, any taking such as ordered by the Board is confiscatory.
>
> (Respondent's factum, para. 38)

In my view, however, the issue before the Board was how much profit ATCO was entitled to earn on its investment in a regulated utility.

93 ATCO argues in the alternative that the Board engaged in impermissible "retroactive rate making". But Alberta is an "original cost" jurisdiction, and no one suggests that the Board's original cost rate making during the 80-plus years this investment has been reflected in ATCO's ratebase was wrong. The Board proposed to apply a portion of the expected profit to future rate making. The effect of the order is prospective, not retroactive. Fixing the going-forward rate of return as well as general supervision of "all gas utilities, and the owners of them" were matters squarely within the Board's statutory mandate.

B. *The Board's Decision*

94 ATCO argues that the Board's decision should be seen as a stand-alone decision divorced from its rate making responsibilities. However, I do not agree that the hearing under s. 26 of the GUA can be isolated in this way from the Board's general regulatory responsibilities. ATCO argues in its factum that

> ... the subject application by [ATCO] to the Board did not concern or relate to a rate application, and the Board was not engaged in fixing rates (if that could provide any justification, which is denied).

(Respondent's factum, para. 98)

95 It seems the Board proceeded with the s. 26 approval hearing separately from a rate setting hearing firstly because ATCO framed the proceeding in that way and secondly because this is the procedure approved by the Alberta Court of Appeal in *TransAlta Utilities Corp. v. Public Utilities Board (Alta.)* (1986), 68 A.R. 171. That case (which I will refer to as *TransAlta (1986)*) is a leading Alberta authority dealing with the allocation of the gain on the disposal of utility assets and the source of what is called the *TransAlta Formula* applied by the Board in this case. Kerans J.A. had this to say, at p. 174.

> I observe parenthetically that I now appreciate that it suits the convenience of everybody involved to resolve issues of this sort, if possible, before a general rate hearing so as to lessen the burden on that already complex procedure.

96 Given this encouragement from the Alberta Court of Appeal, I would place little significance on ATCO's procedural point. As will be seen, the Board's ruling is directly tied into the setting of general rates because two thirds of the profit is taken into account as an offset to ATCO's costs from which its revenue requirement is ultimately derived. As stated, ATCO's profit on the sale of the Calgary property will be a current (not historical) receipt and, if the Board has its way, two thirds of it will be applied to future (not retroactive) rate making.

97 The s. 26 hearing proceeded in two phases. The Board first determined that it would not deny its approval to the proposed sale as it met a "no-harm test" devised over the years by Board practice (it is not to be found in the statutes) (Decision 2001-78). However, the Board linked its approval to subsequent consideration of the financial ramifications, as the Board itself noted (Decision 2002-037):

> The Board approved the Sale in Decision 2001-78 based on evidence that customers did not object to the Sale [and] would not suffer a reduction in services <u>nor would they be exposed to the risk of financial harm as a result of the Sale *that could not be examined in a future proceeding.* On that basis</u> the Board determined that the no-harm test had been satisfied and that the Sale could proceed. [Emphasis added; para. 13.]

98 In effect, ATCO ignores the italicized words. It argues that the Board was *functus* after the first phase of its hearing. However, ATCO itself had agreed to the two-phase procedure, and indeed the second phase was devoted to ATCO's own application for an allocation of the profits on the sale.

99 In the second phase of the s. 26 approval hearing, the Board allocated one third of the net gain to ATCO and two thirds to the rate base (which would benefit ratepayers). The Board spelled out why it considered these conditions to be necessary in the public interest. The Board explained that it was necessary to balance the interests of both shareholders and ratepayers within the framework of what it called "the regulatory compact" (Decision 2002-037, at para. 44). In the Board's view:

> (a) there ought to be a balancing of the interests of the ratepayers and the owners of the utility;
> (b) decisions made about the utility should be driven by both parties' interests;
> (c) to award the entire gain to the ratepayers would deny the utility an incentive to increase its efficiency and reduce its costs; and
> (d) to award the entire gain to the utility might encourage speculation in non-depreciable property or motivate the utility to identify and dispose of properties which have appreciated for reasons other than the best interest of the regulated business.

100 For purposes of this appeal, it is important to set out the Board's policy reasons in its own words:

> To award the entire net gain on the land and buildings to the customers, while beneficial to the customers, could establish an environment that may deter the process wherein the company

> continually assesses its operation to identify, evaluate, and select options that continually increase efficiency and reduce costs.
>
> Conversely, to award the entire net gain to the company may establish an environment where a regulated utility company might be moved to speculate in non-depreciable property or result in the company being motivated to identify and sell existing properties where appreciation has already occurred.
>
> The Board believes that some method of balancing both parties' interests will result in optimization of business objectives for both the customer and the company. Therefore, the Board considers that sharing of the net gain on the sale of the land and buildings collectively in accordance with the TransAlta Formula is equitable in the circumstances of this application and is consistent with past Board decisions. [Emphasis added; paras. 112-14.]

101 The Court was advised that the two-third share allocated to ratepayers would be included in ATCO's rate calculation to set off against the costs included in the rate base and amortized over a number of years.

C. *Standard of Review*

102 The Court's modern approach to this vexed question was recently set out by McLachlin C.J. in *Dr. Q v. College of Physicians and Surgeons of British Columbia*, [2003] 1 S.C.R. 226, 2003 SCC 19, at para. 26:

> In the pragmatic and functional approach, the standard of review is determined by considering four contextual factors - the presence or absence of a privative clause or statutory right of appeal; the expertise of the tribunal relative to that of the reviewing court on the issue in question; the purposes of the legislation and the provision in particular; and, the nature of the question - law, fact, or mixed law and fact. The factors may overlap. The overall aim is to discern legislative intent, keeping in mind the constitutional role of the courts in maintaining the rule of law.

103 I do not propose to cover the ground already set out in the reasons of my colleague Bastarache J. We agree that the standard of review on matters of jurisdiction is correctness. We also agree that the Board's *exercise* of its jurisdiction calls for greater judicial deference. Appeals from the Board are limited to questions of law or jurisdiction. The Board knows a great deal more than the courts about gas utilities, and what limits it is necessary to impose "in the public interest" on their dealings with assets whose cost is included in the rate base. Moreover, it is difficult to think of a broader discretion than that conferred on the Board to "impose any additional conditions that the Board considers necessary in the public interest". The identification of a subjective discretion in the decision maker ("the Board considers necessary"), the expertise of that decision maker and the nature of the decision to be made ("in the public interest"), in my view, call for the most deferential standard, patent unreasonableness.

104 As to the phrase "the Board considers necessary", Martland J. stated in *Calgary Power Ltd. v. Copithorne*, [1959] S.C.R. 24, at p. 34:

> The question as to whether or not the respondent's lands were "necessary" is not one to be determined by the Courts in this case. The question is whether the Minister "deemed" them to be necessary.

See also D. J. M. Brown and J. M. Evans, *Judicial Review of Administrative Action in Canada* (loose-leaf ed.), vol. 1, at para. 14:2622: *"Objective" and "Subjective" Grants of Discretion*.

105 The expert qualifications of a regulatory Board are of "utmost importance in determining the intention of the legislator with respect to the degree of deference to be shown to a tribunal's decision in the absence of a full privative clause", as stated by Sopinka J. in *United Brotherhood of Carpenters and Joiners of America, Local 579 v. Bradco Construction Ltd.*, [1993] 2 S.C.R. 316, at p. 335. He continued:

> Even where the tribunal's enabling statute provides explicitly for appellate review, as was the case in *Bell Canada v. Canada (Canadian Radio-Television and Telecommunications Commission)*, [1989] 1 S.C.R. 1722], it has been stressed that deference should be shown by the appellate tribunal to the opinions of the specialized lower tribunal on matters squarely within its jurisdiction.

(This *dictum* was cited with approval in *Pezim v. British Columbia (Superintendent of Brokers)*, [1994] 2 S.C.R. 557, at p. 592.)

106 A regulatory power to be exercised "in the public interest" necessarily involves accommodation of conflicting economic interests. It has long been recognized that what is "in the public interest" is not really a question of law or fact but is an opinion. In *TransAlta (1986)*, the Alberta Court of Appeal (at para. 24) drew a parallel between the scope of the words "public interest" and the well-known phrase "public convenience and necessity" in its citation of *Memorial Gardens Association (Canada) Ltd. v. Colwood Cemetery Co.*, [1958] S.C.R. 353, where this Court stated, at p. 357:

> [T]he question whether <u>public convenience and necessity</u> requires a certain action is not one of fact. <u>It is predominantly the formulation of an opinion.</u> Facts must, of course, be established to justify a decision by the Commission but that decision is one which cannot be made without a substantial exercise of administrative discretion. In delegating this administrative discretion to the Commission the Legislature has delegated to that body the responsibility of deciding, <u>in the public interest</u>, ... [Emphasis added.]

107 This passage reiterated the *dictum* of Rand J. in *Union Gas Co. of Canada v. Sydenham Gas and Petroleum Co.*, [1957] S.C.R. 185, at p. 190:

> It was argued, and it seems to have been the view of the Court, that the determination of public convenience and necessity was itself a question of fact, but with that I am unable to agree: it is not an objective existence to be ascertained; <u>the determination is the formulation of an opinion, in this case, the opinion of the Board and of the Board only</u>. [Emphasis added.]

108 Of course even such a broad power is not untrammelled. But to say that such a power is capable of abuse does not lead to the conclusion that it should be truncated. I agree on this point with Reid J. (co-author of R. F. Reid and H. David, *Administrative Law and Practice* (2nd ed. 1978), and co-editor of P. Anisman and R. F. Reid, *Administrative Law Issues and Practice* (1995)) who wrote in *Re C.T.C. Dealer Holdings Ltd. and Ontario Securities Commission* (1987), 59 O.R. (2d) 79 (Div. Ct.), in relation to the powers of the Ontario Securities Commission, at p. 97:

> ... when the Commission has acted *bona fide*, with an obvious and honest concern for the public interest, and with evidence to support its opinion, the prospect that the breadth of its discretion might someday tempt it to place itself above the law by misusing that discretion is not something that makes the existence of the discretion bad *per se*, and requires the decision to be struck down.

(The *C.T.C. Dealer Holdings* decision was referred to with apparent approval by this Court in *Committee for the Equal Treatment of Asbestos Minority Shareholders v. Ontario (Securities Commission)*, [2001] 2 S.C.R. 132, 2001 SCC 37, at para. 42.)

109 "Patent unreasonableness" is a highly deferential standard:

A correctness approach means that there is only one proper answer. A patently unreasonable one means that there could have been many appropriate answers, but not the one reached by the decision maker.

(*C.U.P.E.*, at para. 164)

110 Having said all that, in my view nothing much turns on the result on whether the proper standard in that regard is patent unreasonableness (as I view it) or simple reasonableness (as my colleague sees it). As will be seen, the Board's response is well within the range of established regulatory opinions. Hence, even if the Board's conditions were subject to the less deferential standard, I would find no cause for the Court to interfere.

D. *Did the Board Have Jurisdiction to Impose the Conditions It Did on the Approval Order "In the Public Interest"?*

111 ATCO says the Board had no jurisdiction to impose conditions that are "confiscatory". Framing the question in this way, however, assumes the point in issue. The correct point of departure is not to assume that ATCO is entitled to the net gain and then ask if the Board can confiscate it. ATCO's investment of $83,000 was added in increments to its regulatory cost base as the land was acquired from time to time between 1922 and 1965. It is in the nature of a regulated industry that the question of what is a just and equitable return is determined by a board and not by the vagaries of the speculative property market.

112 I do not think the legal debate is assisted by talk of "confiscation". ATCO is prohibited by statute from disposing of the asset without Board approval, and the Board has statutory authority to impose conditions on its approval. The issue thus necessarily turns not on the *existence* of the jurisdiction but on the *exercise* of the Board's jurisdiction to impose the conditions that it did, and in particular to impose a shared allocation of the net gain.

E. *Did the Board Improperly Exercise the Jurisdiction it Possessed to Impose Conditions the Board Considered "Necessary in the Public Interest"?*

113 There is no doubt that there are many approaches to "the public interest". Which approach the Board adopts is largely (and inherently) a matter of opinion and discretion. While the statutory framework of utilities regulation varies from jurisdiction to jurisdiction, and practice in the United States must be read in light of the constitutional protection of property rights in that country, nevertheless Alberta's grant of authority to its Board is more generous than most. ATCO concedes that its "property" claim would have to give way to a contrary legislative intent, but ATCO says such intent cannot be found in the statutes.

114 Most if not all regulators face the problem of how to allocate gains on property whose original cost is included in the rate base but is no longer required to provide the service. There is a wealth of regulatory experience in many jurisdictions that the Board is entitled to (and does) have regard to in formulating its policies. Striking the correct balance in the allocation of gains between ratepayers and investors is a common preoccupation of comparable boards and agencies:

First, it prevents the utility from degrading the quality, or reducing the quantity, of the regulated service so as to harm consumers. Second, it ensures that the utility maximizes the aggregate economic benefits of its operations, and not merely the benefits flowing to some interest group or stakeholder. Third, it specifically seeks to prevent favouritism toward investors to the detriment of ratepayers affected by the transaction.

("The Efficient Allocation of Proceeds from a Utility's Sale of Assets", by P. W. MacAvoy and J. G. Sidak (2001) 22 Energy L.J. 233, at p. 234)

115 The concern with which Canadian regulators view utilities under their jurisdiction that are speculating in land is not new. In *Re Consumers' Gas Co.* (1976), E.B.R.O. 341-I, the Ontario Energy Board considered how to deal with a real estate profit on land which was disposed of at an after-tax profit of over $2 million. The Board stated:

> The Station "B" property was not purchased by Consumers' for land speculation but was acquired for utility purposes. This investment, while non-depreciable, was subject to interest charges and risk paid for through revenues and, until the gas manufacturing plant became obsolete, disposal of the land was not a feasible option. <u>If, in such circumstances, the Board were to permit real estate profit to accrue to the shareholders only, it would tend to encourage real estate speculation with utility capital.</u> In the Board's opinion, the shareholders and the ratepayers should share the benefits of such capital gains. [Emphasis added; para. 326.]

116 Some U.S. regulators also consider it good regulatory policy to allocate part or all of the profit to offset costs in the rate base. In *Re Boston Gas Company* (1982), 49 P.U.R. 4th 1 (Mass. D.P.U.), the regulator allocated a gain on the sale of land to ratepayers, stating:

> The company and its shareholders have received a return on the use of these parcels while they have been included in rate base, and are not entitled to any additional return as a result of their sale. <u>To hold otherwise would be to find that a regulated utility company may speculate in nondepreciable utility property and, despite earning a reasonable rate of return from its customers on that property, may also accumulate a windfall through its sale.</u> We find this to be an uncharacteristic risk/reward situation for a regulated utility to be in with respect to its plant in service. [Emphasis added.]

117 Canadian regulators other than the Board are also concerned with the prospect that decisions of utilities in their regulated business may be skewed under the undue influence of prospective profits on land sales. In *Re Consumers' Gas Co.* (1991), E.B.R.O. 465, the Ontario Energy Board determined that a $1.9 million gain on sale of land should be divided equally between shareholders and ratepayers. It held that

> ... the allocation of 100 percent of the profit from land sales to either the shareholders or the ratepayers might diminish the recognition of the valid concerns of the excluded party. For example, the timing and intensity of land purchase and sales negotiations could be skewed to favour or disregard the ultimate beneficiary (para. 3.3.8).

118 The Board's principle of dividing the gain between investors and ratepayers is consistent, as well, with *Re Natural Resource Gas Ltd.*, RP-2002-0147; EB-2002-0446, in which the Ontario Energy Board addressed the allocation of a profit on the sale of land and buildings and again stated:

> The Board finds that it is reasonable in the circumstances that the capital gains be shared equally between the Company and its customers. In making this finding the Board has considered the non-recurring nature of this transaction (para. 45).

119 The wide variety of regulatory treatment of such gains was noted by Kerans J.A. in *TransAlta (1986)*, at pp. 175-76, including *Re Boston Gas Co.* mentioned earlier. In *TransAlta (1986)*, the Board characterized TransAlta's gain on the disposal of land and buildings included in its Edmonton "franchise" as "revenue" within the meaning of the *Hydro and Electric Energy Act*, R.S.A. 1980, c. H-13. (The case therefore did not deal with the power to impose conditions "the Board considers necessary in the public interest".) Kerans J.A. said (at p. 176):

> I do not agree with the Board's decision for reasons later expressed, but it would be fatuous to deny that its interpretation [of the word "revenue"] is one which the word can reasonably bear.

Kerans J.A. went on to find that in that case "[t]he compensation was, for all practical purposes, compensation for loss of franchise" (p. 180) and on that basis the gain in these "unique circumstances" (p. 179) could not, as a matter of law, be characterized as revenue, i.e. applying a correctness standard. The range of regulatory practice on the "gains on sale" issue was similarly noted by Goldie J.A. in *Yukon Energy Corp. v. Utilities Board* (1996), 74 B.C.A.C. 58; 121 W.A.C. 58 (Y.C.A.), at para. 85.

120 A survey of recent regulatory experience in the United States reveals the wide variety of treatment in that country of gains on the sale of undepreciated land. The range includes proponents of ATCO's preferred allocation as well as proponents of the solution adopted by the Board in this case:

> Some jurisdictions have concluded that as a matter of equity, shareholders alone should benefit from any gain realized on appreciated real estate, because ratepayers generally pay only for taxes on the land and do not contribute to the cost of acquiring the property and pay no depreciation expenses. Under this analysis, ratepayers assume no risk for losses and acquire no legal or equitable interest in the property, but rather pay only for the use of the land in utility service.
>
> Other jurisdictions claim that ratepayers should retain some of the benefits associated with the sale of property dedicated to utility service. Those jurisdictions that have adopted an equitable sharing approach agree that a review of regulatory and judicial decisions on the issue does not reveal any general principle that requires the allocation of benefits solely to shareholders; rather, the cases show only a general prohibition against sharing benefits on the sale property that has never been reflected in utility rates.
>
> (P. S. Cross, "Rate Treatment of Gain on Sale of Land: Ratepayer Indifference, A New Standard?" (1990), *Public Utilities Fortnightly* 44, at p. 44)

Regulatory opinion in the United States favourable to the solution adopted here by the Board is illustrated by *Re Arizona Public Service Co.* (1988), 91 P.U.R. 4th 337, 1988 WL 391394 (Ariz. C.C.):

> To the extent any general principles can be gleaned from the decisions in other jurisdictions they are: (1) the utility's stockholders are not automatically entitled to the gains from all sales of utility property; and (2) ratepayers are not entitled to all or any part of a gain from the sale of property which has never been reflected in the utility's rates.

121 Assets purchased with capital reflected in the rate base come and go, but the utility itself endures. What was done by the Board in this case is quite consistent with the "enduring enterprise" theory espoused, for example, in *Re Southern California Water Co.* (1992), 43 C.P.U.C. 2d 596, 1992 WL 584058. In that case, Southern California Water had asked for approval to sell an old headquarters building and the issue was how to allocate its profits on the sale. The Commission held:

> Working from the principle of the "enduring enterprise", the gain-on-sale from this transaction should remain within the utility's operations rather than being distributed in the short run directly to either ratepayers or shareholders. The "enduring enterprise" principle, is neither novel nor radical. It was clearly articulated by the Commission in its seminal 1989 policy decision on the issue of gain-on-sale, D. 89-07-016, 32 Cal. P.U.C. 2d 233 (Redding). Simply stated, to the extent that a utility realizes a gain-on-sale from the liquidation of an asset and replaces it with another asset or obligation while at the same time its responsibility to serve its customers is neither relieved nor reduced, then any gain-on-sale should remain within the utility's operation.

122 In my view, neither the Alberta statutes nor regulatory practice in Alberta and elsewhere dictates the answer to the problems confronting the Board. It would have been open to the Board to allow ATCO's application for the entire profit. But the solution it adopted was quite within its statutory authority and does not call for judicial intervention.

F. *ATCO's Arguments*

123 Most of ATCO's principal submissions have already been touched on but I will repeat them here for convenience. ATCO does not really dispute the Board's ability to impose conditions on the sale of land. Rather, ATCO says that what the Board did here violates a number of basic legal protections and principles. It asks the Court to clip the Board's wings.

124 Firstly, ATCO says that customers do not acquire any proprietary right in the company's assets. ATCO, rather than its customers, originally purchased the property, held title to it, and therefore was entitled to any gain on its sale. An allocation of profit to the customers would amount to a confiscation of the corporation's property.

125 Secondly, ATCO says its retention of 100% of the gain has nothing to do with the so-called "regulatory compact". The gas customers paid what the Board regarded over the years as a fair price for safe and reliable service. That is what the ratepayers got and that is all they were entitled to. The Board's allocation of part of the profit to the ratepayers amounts to impermissible "retroactive" rate setting.

126 Thirdly, utilities are not entitled to include in the rate base an amount for *depreciation* on land and ratepayers have therefore not repaid ATCO any part of ATCO's original cost, let alone the present value. The treatment accorded gain on sales of depreciated property therefore does not apply.

127 Fourthly, ATCO complains that the Board's solution is asymmetrical. Ratepayers are given part of the benefit of an increase in land values without, in a falling market, bearing any part of the burden of losses on the disposition of land.

128 In my view, these are all arguments that should be (and were) properly directed to the Board. There are indeed precedents in the regulatory field for what ATCO proposes, just as there are precedents for what the ratepayers proposed. It was for the Board to decide what conditions in these particular circumstances were necessary in the public interest. The Board's solution in this case is well within the range of reasonable options, as I will endeavour to demonstrate.

1. <u>The Confiscation Issue</u>

129 In its factum, ATCO says that "[t]he property belonged to the owner of the utility and the Board's proposed distribution cannot be characterized otherwise than as being confiscatory" (respondent's factum, para. 6). ATCO's argument overlooks the obvious difference between investment in an unregulated business and investment in a regulated utility where the regulator sets the return on investment, not the market place. In *Re Southern California Gas Co.* (1990), 38 C.P.U.C. 2d 166, 118 P.U.R. 4th 81, 1990 WL 488654 ("*SoColGas*"), the regulator pointed out:

> In the non-utility private sector, investors are not guaranteed to earn a fair return on such sunk investment. Although shareholders and bondholders provide the initial capital investment, the ratepayers pay the taxes, maintenance, and other costs of carrying utility property in rate base over the years, and thus insulate utility investors from the risk of having to pay those costs. Ratepayers also pay the utility a fair return on property (including land) while it is in rate base, compensate the utility for the diminishment of the value of its depreciable property over time through depreciation accounting, and bear the risk that they must pay depreciation and a return on prematurely retired rate base property.

(It is understood, of course, that the Board does not appropriate the actual proceeds of sale. What happens is that an amount *equivalent* to two-thirds of the profit is included in the calculation of ATCO's current cost base for rate making purposes. In that way, there is a notional distribution of the benefit of the gain amongst the competing stakeholders.)

130 ATCO's argument is frequently asserted in the United States under the flag of constitutional protection for "property". Constitutional protection has not however prevented allocation of all or part of such gains to the U.S. ratepayers. One of the leading U.S. authorities is *Democratic Central Committee of the District of Columbia v. Washington Metropolitan Area Transit Commission*, 485 F.2d 786 (D.C. Cir. 1973). In that case, the assets at issue were parcels of real estate which had been employed in mass transit operations but which were no longer needed when the transit system converted to buses. The regulator awarded the profit on the appreciated land values to the shareholders but the Court of Appeals reversed the decision, using language directly applicable to ATCO's "confiscation" argument:

> We perceive no impediment, constitutional or otherwise, to recognition of a ratemaking principle enabling ratepayers to benefit from appreciations in value of utility properties accruing while in service. We believe the doctrinal consideration upon which pronouncements to the contrary have primarily rested has lost all present-day vitality. Underlying these pronouncements is a basic legal and economic thesis - sometimes articulated, sometimes implicit - that utility assets, though dedicated to the public service, remain exclusively the property of the utility's investors, and that growth in value is an inseparable and inviolate incident of that property interest. The precept of private ownership historically pervading our jurisprudence led naturally to such a thesis, and early decisions in the ratemaking field lent some support to it; if still viable, it strengthens the investor's claim. We think, however, after careful exploration, that the foundations for that approach, and the conclusion it seemed to indicate, have long since eroded away (p. 800).

The court's reference to "pronouncements" which have "lost all present-day vitality" likely includes *Board of Public Utility Commissioners v. New York Telephone Co.*, 271 U.S. 23 (1926), a decision relied upon in this case by ATCO. In that case, the Supreme Court of the United States said (at p. 31):

> Customers pay for service, not for the property used to render it. Their payments are not contributions to depreciation or other operating expenses or to capital of the company. By paying bills for service they do not acquire any interest, legal or equitable, in the property used for their convenience or in the funds of the company. Property paid for out of moneys received for service belongs to the company just as does that purchased out of proceeds of its bonds and stock.

In that case, the regulator belatedly concluded that the level of depreciation allowed the New York Telephone Company had been excessive in past years and sought to remedy the situation in the current year by retroactively adjusting the cost base. The court held that the regulator had no power to re-open past rates. The financial fruits of the regulator's errors in past years now belonged to the company. That is not this case. No one contends that the Board's prior rates, based on ATCO's original investment, were wrong. In 2001, when the matter came before the Board, the Board had jurisdiction to approve or not approve the proposed sale. It was not a done deal. The receipt of any profit by ATCO was prospective only. As explained in *Re Arizona Public Service Co.*:

> In New York Telephone, the issue presented was whether a state regulatory commission could use excessive depreciation accruals from prior years to reduce rates for future service and thereby set rates which did not yield a just return. ... the Court simply reiterated and provided the reasons for a ratemaking truism: rates must be designed to produce enough revenue to pay current [reasonable] operating expenses and provide a fair return to the utility's investors. If it turns out that, for whatever reason, existing rates have produced too much or too little income, the past is past. <u>Rates are raised or lowered to reflect current conditions; they are not designed to pay back past excessive profits or recoup past operating losses.</u> In contrast, the issue in this proceeding is

> whether for ratemaking purposes a utility's test year income from sales of utility service can include its income from sales of utility property. The United States Supreme Court's decision in New York Telephone does not address that issue. [Emphasis added.]

131 More recently, the allocation of gain on sale was addressed by the California Public Utilities Commission in *SoCalGas*. In that case, as here, the utility (SoCalGas) wished to sell land and buildings located (in that case) in downtown Los Angeles. The Commission apportioned the gain on sale between the shareholders and the ratepayers, concluding that:

> We believe that the issue of who owns the utility property providing utility service has become a red herring in this case, and that ownership alone does not determine who is entitled to the gain on the sale of the property providing utility service when it is removed from rate base and sold.

132 ATCO argues in its factum that ratepayers "do not acquire any interest, legal or equitable, in the property used to provide the service or in the funds of the owner of the utility" (para. 2). In *SoCalGas*, the regulator disposed of this point as follows:

> No one seriously argues that ratepayers acquire title to the physical property assets used to provide utility service; DRA [Division of Ratepayer Advocates] argues that the gain on sale should reduce future revenue requirements not because ratepayers own the property, but rather because they paid the costs and faced the risks associated with that property while it was in rate base providing public service.

This "risk" theory applies in Alberta as well. Over the last 80 years, there have been wild swings in Alberta real estate, yet through it all, in bad times and good, the ratepayers have guaranteed ATCO a just and equitable return on its investment in *this* land and *these* buildings.

133 The notion that the division of risk justifies a division of the net gain was also adopted by the regulator in *SoCalGas*:

> Although the shareholders and bondholders provided the initial capital investment, the ratepayers paid the taxes, maintenance, and other costs of carrying the land and buildings in rate base over the years, and paid the utility a fair return on its unamortized investment in the land and buildings while they were in rate base.

In other words, even in the United States, where property rights are constitutionally protected, ATCO's "confiscation" point is rejected as an oversimplification.

134 My point is not that the Board's allocation in this case is necessarily correct in all circumstances. Other regulators have determined that the public interest requires a different allocation. The Board proceeds on a "case-by-case" basis. My point simply is that the Board's response in this case cannot be considered "confiscatory" in any proper use of the term, and is well within the range of what are regarded in comparable jurisdictions as appropriate regulatory responses to the allocation of the gain on sale of land whose original investment has been included by the utility itself in its rate base. The Board's decision is protected by a deferential standard of review and in my view it should not have been set aside.

2. <u>The Regulatory Compact</u>

135 The Board referred in its decision to the "regulatory compact" which is a loose expression suggesting that in exchange for a statutory monopoly and receipt of revenue on a cost plus basis, the utility accepts limitations on its rate of return and its freedom to do as it wishes with property whose cost is reflected in its rate base. This was expressed in the *Washington Metropolitan Area Transit* case by the U.S. Court of Appeals as follows (at p. 806):

> The ratemaking process involves fundamentally "a balancing of the investor and the consumer interests." The investor's interest lies in the integrity of his investment and a fair opportunity for a reasonable return thereon. The consumer's interest lies in governmental protection against unreasonable charges for the monopolistic service to which he subscribes. In terms of property value appreciations, the balance is best struck at the point at which the interests of both groups receive maximum accommodation.

136 ATCO considers that the Board's allocation of profit violated the regulatory compact not only because it is confiscatory but because it amounts to "retroactive rate making". In *Northwestern Utilities Ltd. v. City of Edmonton*, [1979] 1 S.C.R. 684, Estey J. stated, at p. 691:

> It is clear from many provisions of *The Gas Utilities Act* that the Board must act prospectively and may not award rates which will recover expenses incurred in the past and not recovered under rates established for past periods.

137 As stated earlier, the Board in this case was addressing a prospective receipt and allocated two thirds of it to a prospective (not retroactive) rate making exercise. This is consistent with regulatory practice, as is illustrated by *New York Water Service Corp. v. Public Service Commission*, 208 N.Y.S. 2d 587 (1960). In that case, a utility commission ruled that gains on the sale of real estate should be taken into account to reduce rates annually over the following period of 17 years (p. 864):

> If land is sold at a profit, it is required that the profit be added to, i.e., "credited to", the depreciation reserve, so that there is a corresponding reduction of the rate base and resulting return.

The regulator's order was upheld by the New York State Supreme Court (Appellate Division).

138 More recently, in *Re Compliance with the Energy Policy Act of 1992* (1995), 62 C.P.U.C. 2d 517, WL 768628, the regulator commented:

> ... we found it appropriate to allocate the principal amount of the gain to offset future costs of headquarters facilities, because ratepayers had borne the burden of risks and expenses while the property was in ratebase. At the same time, we found that it was equitable to allocate a portion of the benefits from the gain-on-sale to shareholders in order to provide a reasonable incentive to the utility to maximize the proceeds from selling such property and compensate shareholders for any risks borne in connection with holding the former property.

139 The emphasis in all these cases is on balancing the interests of the shareholders and the ratepayers. This is perfectly consistent with the "regulatory compact" approach reflected in the Board doing what it did in this case.

3. Land as a Non-Depreciable Asset

140 The Alberta Court of Appeal drew a distinction between gains on sale of land, whose original cost is not depreciated (and thus is not repaid in increments through the rate base) and depreciated property such as buildings where the rate base does include a measure of capital repayment and which in that sense the ratepayers have "paid for". The Alberta Court of Appeal held that the Board was correct to credit the rate base with an amount equivalent to the depreciation paid in respect of the buildings (this is the subject matter of ATCO's cross-appeal). Thus in this case, the land was still carried on ATCO's books at its original price of $83,720 whereas the original $596,591 cost of the buildings had been depreciated through the rates charged customers to a net book value of $141,525.

141 Regulatory practice shows that many (not all) regulators also do not accept the distinction (for this purpose) between depreciable and non-depreciable assets. In *Re Boston Gas Co.* for example (cited in *TransAlta (1986)*, at p. 176), the regulator held:

> ... the company's ratepayers have been paying a return on this land as well as all other costs associated with its use. The fact that land is a nondepreciable asset because its useful value is not ordinarily diminished through use is, we find, irrelevant to the question of who is entitled to the proceeds on the sales of this land.

142 In *SoCalGas*, as well, the Commission declined to make a distinction between the gain on sale of depreciable, as compared to non-depreciable, property, stating "We see little reason why land sales should be treated differently." The decision continued:

> In short, whether an asset is depreciated for ratemaking purposes or not, ratepayers commit to paying a return on its book value for as long as it is used and useful. Depreciation simply recognizes the fact that certain assets are consumed over a period of utility service while others are not. <u>The basic relationship between the utility and its ratepayers is the same for depreciable and non-depreciable assets.</u> [Emphasis added.]

143 In *Re California Water Service Co.* (1996), 66 C.P.U.C. 2d 100, 1996 WL 293205, the regulator commented that:

> Our decisions generally find no reason to treat gain on the sale of nondepreciable property, such as bare land, different[ly] than gains on the sale of depreciable rate base assets and land in PHFU [plant held for future use].

144 Again, my point is not that the regulator *must* reject any distinction between depreciable and non-depreciable property. Simply, my point is that the distinction does not have the controlling weight as contended by ATCO. In Alberta, it is up to the Board to determine what allocations are necessary in the public interest as conditions of the approval of sale. ATCO's attempt to limit the Board's discretion by reference to various doctrine is not consistent with the broad statutory language used by the Alberta legislature and should be rejected.

4. <u>Lack of Reciprocity</u>

145 ATCO argues that the customers should not profit from a rising market because if the land loses value it is ATCO, and not the ratepayers, that will absorb the loss. However, the material put before the Court suggests that the Board takes into account both gains *and* losses. In the following decisions the Board stated, repeated, and repeated again its "general rule" that

> ... the Board considers that any profit <u>or loss</u> (being the difference between the net book value of the assets and the sale price of those assets) resulting from the disposal of utility assets <u>should accrue to the customers of the utility</u> and not to the owner of the utility. [Emphasis added.]

(See *TransAlta Utilities Corp.* (1984), Alta. P.U.B. Decision No. E84116, at p. 17; *TransAlta Utilities Corp.* (1984), Alta. P.U.B. Decision No. E84115, at p. 12; *Re Gas Utilities Act and Public Utilities Board Act*, (1984), Alta. P.U.B. Decision No. E84113, at p. 23.)

146 In *Alberta Government Telephones*, the Board reviewed a number of regulatory approaches (including *Re Boston Gas Co.*, previously mentioned) with respect to gains on sale and concluded with respect to its own practice, at p. 12:

> The Board is aware that it has not applied any consistent formula or rule which would automatically determine the accounting procedure to be followed in the treatment of gains or losses on the disposition of utility assets. The reason for this is that the Board's determination of

> what is fair and reasonable rests on the merits or facts of each case.

147 ATCO's contention that it alone is burdened with the risk on land that *declines* in value overlooks the fact that in a falling market, the utility continues to be entitled to a rate of return on its original investment even if the market value at the time is substantially less than its original investment. As pointed out in *SoCalGas*:

> If the land actually does depreciate in value below its original cost, then one view could be that the steady rate of return [the ratepayers] have paid for the land over time has actually overcompensated investors. Thus, there is symmetry of risk and reward associated with rate base land just as there is with regard to depreciable rate base property.

II. Conclusion

148 In summary, s. 15(3) of the AEUBA authorized the Board in dealing with ATCO's application to approve the sale of the subject land and buildings to "impose any additional conditions that the Board considers necessary in the public interest". In the exercise of that authority, and having regard to the Board's "general supervision over all gas utilities, and the owners of them" (GUA, s. 22(1)), the Board made an allocation of the net gain for the public policy reasons which it articulated in its decision. Perhaps not every regulator and not every jurisdiction would exercise the power in the same way, but the allocation of the gain on an asset ATCO sought to withdraw from the rate base was a decision the Board was mandated to make. It is not for the Court to substitute its own view of what is "necessary in the public interest".

III. Disposition

149 I would allow the appeal, set aside the decision of the Alberta Court of Appeal, and restore the decision of the Board, with costs to the City of Calgary both in this Court and in the court below. ATCO's cross-appeal should be dismissed with costs.

* * * * *

APPENDIX

Alberta Energy and Utilities Board Act, R.S.A. 2000, c. A-17

[Jurisdiction]

13 All matters that may be dealt with by the ERCB or the PUB under any enactment or as otherwise provided by law shall be dealt with by the Board and are within the exclusive jurisdiction of the Board.

[Powers of the Board]

15(1) For the purposes of carrying out its functions, the Board has all the powers, rights and privileges of the ERCB and the PUB that are granted or provided for by any enactment or by law.

(2) In any case where the ERCB, the PUB or the Board may act in response to an application, complaint, direction, referral or request, the Board may act on its own initiative or motion.

(3) Without restricting subsection (1), the Board may do all or any of the following:

> (a) make any order that the ERCB or the PUB may make under any enactment;
> (b) with the approval of the Lieutenant Governor in Council, make any order that the ERCB may, with the approval of the Lieutenant Governor in Council, make under any

enactment;

(c) with the approval of the Lieutenant Governor in Council, make any order that the PUB may, with the approval of the Lieutenant Governor in Council, make under any enactment;

(d) with respect to an order made by the Board, the ERCB or the PUB in respect of matters referred to in clauses (a) to (c), make any further order and impose any additional conditions that the Board considers necessary in the public interest;

(e) make an order granting the whole or part only of the relief applied for;

(f) where it appears to the Board to be just and proper, grant partial, further or other relief in addition to, or in substitution for, that applied for as fully and in all respects as if the application or matter had been for that partial, further or other relief.

[Appeals]

26(1) Subject to subsection (2), an appeal lies from the Board to the Court of Appeal on a question of jurisdiction or on a question of law.

(2) Leave to appeal may be obtained from a judge of the Court of Appeal only on an application made

(a) within 30 days from the day that the order, decision or direction sought to be appealed from was made, or

(b) within a further period of time as granted by the judge where the judge is of the opinion that the circumstances warrant the granting of that further period of time.

[Exclusion of prerogative writs]

27 Subject to section 26, every action, order, ruling or decision of the Board or the person exercising the powers or performing the duties of the Board is final and shall not be questioned, reviewed or restrained by any proceeding in the nature of an application for judicial review or otherwise in any court.

Gas Utilities Act, R.S.A. 2000, c. G-5

[Supervision]

22(1) The Board shall exercise a general supervision over all gas utilities, and the owners of them, and may make any orders regarding equipment, appliances, extensions of works or systems, reporting and other matters, that are necessary for the convenience of the public or for the proper carrying out of any contract, charter or franchise involving the use of public property or rights.

(2) The Board shall conduct all inquiries necessary for the obtaining of complete information as to the manner in which owners of gas utilities comply with the law, or as to any other matter or thing within the jurisdiction of the Board under this Act.

[Investigation of gas utility]

24(1) The Board, on its own initiative or on the application of a person having an interest, may investigate any matter concerning a gas utility.

[Designated gas utilities]

26(1) The Lieutenant Governor in Council may by regulation designate those owners of gas utilities to which this section and section 27 apply.

(2) No owner of a gas utility designated under subsection (1) shall

(a) issue any

(i) of its shares or stock, or
(ii) bonds or other evidences of indebtedness, payable in more than one year from the date of them,

unless it has first satisfied the Board that the proposed issue is to be made in accordance with law and has obtained the approval of the Board for the purposes of the issue and an order of the Board authorizing the issue,

(b) capitalize

(i) its right to exist as a corporation,
(ii) a right, franchise or privilege in excess of the amount actually paid to the Government or a municipality as the consideration for it, exclusive of any tax or annual charge, or
(iii) a contract for consolidation, amalgamation or merger,

(c) without the approval of the Board, capitalize any lease, or
(d) without the approval of the Board,

(i) sell, lease, mortgage or otherwise dispose of or encumber its property, franchises, privileges or rights, or any part of it or them, or
(ii) merge or consolidate its property, franchises, privileges or rights, or any part of it or them,

and a sale, lease, mortgage, disposition, encumbrance, merger or consolidation made in contravention of this clause is void, but nothing in this clause shall be construed to prevent in any way the sale, lease, mortgage, disposition, encumbrance, merger or consolidation of any of the property of an owner of a gas utility designated under subsection (1) in the ordinary course of the owner's business.

[Prohibited share transactions]

27(1) Unless authorized to do so by an order of the Board, the owner of a gas utility designated under section 26(1) shall not sell or make or permit to be made on its books any transfer of any share or shares of its capital stock to a corporation, however incorporated, if the sale or transfer, by itself or in connection with previous sales or transfers, would result in the vesting in that corporation of more than 50% of the outstanding capital stock of the owner of the gas utility.

[Powers of Board]

36 The Board, on its own initiative or on the application of a person having an interest, may by order in writing, which is to be made after giving notice to and hearing the parties interested,

(a) fix just and reasonable individual rates, joint rates, tolls or charges or schedules of them, as well as commutation and other special rates, which shall be imposed, observed and followed afterwards by the owner of the gas utility,

(b) fix proper and adequate rates and methods of depreciation, amortization or depletion in respect of the property of any owner of a gas utility, who shall make the owner's depreciation, amortization or depletion accounts conform to the rates and methods fixed by the Board,

(c) fix just and reasonable standards, classifications, regulations, practices, measurements or service, which shall be furnished, imposed, observed and followed thereafter by the owner of the gas utility,

(d) require an owner of a gas utility to establish, construct, maintain and operate, but in compliance with this and any other Act relating to it, any reasonable extension of the owner's existing facilities when in the judgment of the Board the extension is reasonable and practical and will furnish sufficient business to justify its construction and maintenance, and when the financial position of the owner of the gas utility reasonably warrants the original expenditure required in making and operating the extension, and

(e) require an owner of a gas utility to supply and deliver gas to the persons, for the purposes, at the rates, prices and charges and on the terms and conditions that the Board directs, fixes or imposes.

[Rate base]

37(1) In fixing just and reasonable rates, tolls or charges, or schedules of them, to be imposed, observed and followed afterwards by an owner of a gas utility, the Board shall determine a rate base for the property of the owner of the gas utility used or required to be used to provide service to the public within Alberta and on determining a rate base it shall fix a fair return on the rate base.

(2) In determining a rate base under this section, the Board shall give due consideration

(a) to the cost of the property when first devoted to public use and to prudent acquisition cost to the owner of the gas utility, less depreciation, amortization or depletion in respect of each, and

(b) to necessary working capital.

(3) In fixing the fair return that an owner of a gas utility is entitled to earn on the rate base, the Board shall give due consideration to all facts that in its opinion are relevant.

[Excess revenues or losses]

40 In fixing just and reasonable rates, tolls or charges, or schedules of them, to be imposed, observed and followed afterwards by an owner of a gas utility,

(a) the Board may consider all revenues and costs of the owner that are in the Board's opinion applicable to a period consisting of

(i) the whole of the fiscal year of the owner in which a proceeding is initiated for the fixing of rates, tolls or charges, or schedules of them,

(ii) a subsequent fiscal year of the owner, or

(iii) 2 or more of the fiscal years of the owner referred to in subclauses (i) and (ii) if they are consecutive,

and need not consider the allocation of those revenues and costs to any part of that period,

(b) the Board may give effect to that part of any excess revenue received or any revenue deficiency incurred by the owner that is in the Board's opinion applicable to the whole of the fiscal year of the owner in which a proceeding is initiated for the fixing of rates, tolls or charges, or schedules of them, that the Board determines is just and reasonable,
(c) the Board may give effect to that part of any excess revenue received or any revenue deficiency incurred by the owner after the date on which a proceeding is initiated for the fixing of rates, tolls or charges, or schedules of them, that the Board determines has been due to undue delay in the hearing and determining of the matter, and
(d) the Board shall by order approve

(i) the method by which, and
(ii) the period, including any subsequent fiscal period, during which,

any excess revenue received or any revenue deficiency incurred, as determined pursuant to clause (b) or (c), is to be used or dealt with.

[General powers of Board]

59 For the purposes of this Act, the Board has the same powers in respect of the plant, premises, equipment, service and organization for the production, distribution and sale of gas in Alberta, and in respect of the business of an owner of a gas utility and in respect of an owner of a gas utility, that are by the *Public Utilities Board Act* conferred on the Board in the case of a public utility under that Act.

Public Utilities Board Act, R.S.A. 2000, c. P-45

[Jurisdiction and powers]

36(1) The Board has all the necessary jurisdiction and power

(a) to deal with public utilities and the owners of them as provided in this Act;
(b) to deal with public utilities and related matters as they concern suburban areas adjacent to a city, as provided in this Act.

(2) In addition to the jurisdiction and powers mentioned in subsection (1), the Board has all necessary jurisdiction and powers to perform any duties that are assigned to it by statute or pursuant to statutory authority.

(3) The Board has, and is deemed at all times to have had, jurisdiction to fix and settle, on application, the price and terms of purchase by a council of a municipality pursuant to section 47 of the *Municipal Government Act*

(a) before the exercise by the council under that provision of its right to purchase and without binding the council to purchase, or
(b) when an application is made under that provision for the Board's consent to the purchase, before hearing or determining the application for its consent.

[General power]

37 In matters within its jurisdiction the Board may order and require any person or local authority to do forthwith or within or at a specified time and in any manner prescribed by the Board, so far as it is not inconsistent with this Act or any other Act conferring jurisdiction, any act, matter or thing that the person or local authority is or may be required to do under this Act or under any other general or special Act, and may forbid the doing or continuing of any act, matter or thing that is in contravention of any such Act or of any regulation, rule, order or direction of the Board.

[Investigation of utilities and rates]

80 When it is made to appear to the Board, on the application of an owner of a public utility or of a municipality or person having an interest, present or contingent, in the matter in respect of which the application is made, that there is reason to believe that the tolls demanded by an owner of a public utility exceed what is just and reasonable, having regard to the nature and quality of the service rendered or of the commodity supplied, the Board

(a) may proceed to hold any investigation that it thinks fit into all matters relating to the nature and quality of the service or the commodity in question, or to the performance of the service and the tolls or charges demanded for it,

(b) may make any order respecting the improvement of the service or commodity and as to the tolls or charges demanded, that seems to it to be just and reasonable, and

(c) may disallow or change, as it thinks reasonable, any such tolls or charges that, in its opinion, are excessive, unjust or unreasonable or unjustly discriminate between different persons or different municipalities, but subject however to any provisions of any contract existing between the owner of the public utility and a municipality at the time the application is made that the Board considers fair and reasonable.

[Supervision by Board]

85(1) The Board shall exercise a general supervision over all public utilities, and the owners of them, and may make any orders regarding extension of works or systems, reporting and other matters, that are necessary for the convenience of the public or for the proper carrying out of any contract, charter or franchise involving the use of public property or rights.

[Investigation of public utility]

87(1) The Board may, on its own initiative, or on the application of a person having an interest, investigate any matter concerning a public utility.

(2) When in the opinion of the Board it is necessary to investigate a public utility or the affairs of its owner, the Board shall be given access to and may use any books, documents or records with respect to the public utility and in the possession of any owner of the public utility or municipality or under the control of a board, commission or department of the Government.

(3) A person who directly or indirectly controls the business of an owner of a public utility within Alberta and any company controlled by that person shall give the Board or its agent access to any of the books, documents and records that relate to the business of the owner or shall furnish any information in respect of it required by the Board.

[Fixing of rates]

89 The Board, either on its own initiative or on the application of a person having an interest, may by order in writing, which is to be made after giving notice to and hearing the parties interested,

(a) fix just and reasonable individual rates, joint rates, tolls or charges, or schedules of them, as well as commutation, mileage or kilometre rate and other special rates, which shall be imposed, observed and followed subsequently by the owner of the public utility;

(b) fix proper and adequate rates and methods of depreciation, amortization or depletion in respect of the property of any owner of a public utility, who shall make the owner's depreciation, amortization or depletion accounts conform to the rates and methods fixed by the Board;

(c) fix just and reasonable standards, classifications, regulations, practices, measurements or service, which shall be furnished, imposed, observed and followed subsequently by the owner of the public utility;

(d) repealed;

(e) require an owner of a public utility to establish, construct, maintain and operate, but in compliance with other provisions of this or any other Act relating to it, any reasonable extension of the owner's existing facilities when in the judgment of the Board the extension is reasonable and practical and will furnish sufficient business to justify its construction and maintenance, and when the financial position of the owner of the public utility reasonably warrants the original expenditure required in making and operating the extension.

[Determining rate base]

90(1) In fixing just and reasonable rates, tolls or charges, or schedules of them, to be imposed, observed and followed subsequently by an owner of a public utility, the Board shall determine a rate base for the property of the owner of a public utility used or required to be used to provide service to the public within Alberta and on determining a rate base it shall fix a fair return on the rate base.

(2) In determining a rate base under this section, the Board shall give due consideration

(a) to the cost of the property when first devoted to public use and to prudent acquisition cost to the owner of the public utility, less depreciation, amortization or depletion in respect of each, and

(b) to necessary working capital.

(3) In fixing the fair return that an owner of a public utility is entitled to earn on the rate base, the Board shall give due consideration to all those facts that, in the Board's opinion, are relevant.

[Revenue and costs considered]

91(1) In fixing just and reasonable rates, tolls or charges, or schedules of them, to be imposed, observed and followed by an owner of a public utility,

(a) the Board may consider all revenues and costs of the owner that are in the Board's opinion applicable to a period consisting of

(i) the whole of the fiscal year of the owner in which a proceeding is initiated for the fixing of rates, tolls or charges, or schedules of them,

(ii) a subsequent fiscal year of the owner, or

(iii) 2 or more of the fiscal years of the owner referred to in subclauses (i) and (ii) if they are consecutive,

and need not consider the allocation of those revenues and costs to any part of such a period,

(b) the Board shall consider the effect of the *Small Power Research and Development Act* on the revenues and costs of the owner with respect to the generation, transmission and distribution of electric energy,

(c) the Board may give effect to that part of any excess revenue received or any revenue deficiency incurred by the owner that is in the Board's opinion applicable to the whole of the fiscal year of the owner in which a proceeding is initiated for the fixing of rates, tolls or charges, or schedules of them, as the Board determines is just and reasonable,

(d) the Board may give effect to such part of any excess revenue received or any revenue deficiency incurred by the owner after the date on which a proceeding is initiated for the fixing of rates, tolls or charges, or schedules of them, as the Board determines has been due to undue delay in the hearing and determining of the matter, and

(e) the Board shall by order approve the method by which, and the period (including any subsequent fiscal period) during which, any excess revenue received or any revenue deficiency incurred, as determined pursuant to clause (c) or (d), is to be used or dealt with.

[Designated public utilities]

101(1) The Lieutenant Governor in Council may by regulation designate those owners of public utilities to which this section and section 102 apply.

(2) No owner of a public utility designated under subsection (1) shall

(a) issue any

(i) of its shares or stock, or

(ii) bonds or other evidences of indebtedness, payable in more than one year from the date of them,

unless it has first satisfied the Board that the proposed issue is to be made in accordance with law and has obtained the approval of the Board for the purposes of the issue and an order of the Board authorizing the issue,

(b) capitalize

(i) its right to exist as a corporation,

(ii) a right, franchise or privilege in excess of the amount actually paid to the Government or a municipality as the consideration for it, exclusive of any tax or annual charge, or

(iii) a contract for consolidation, amalgamation or merger,

(c) without the approval of the Board, capitalize any lease, or

(d) without the approval of the Board,

(i) sell, lease, mortgage or otherwise dispose of or encumber its property, franchises, privileges or rights, or any part of them, or

(ii) merge or consolidate its property, franchises, privileges or rights, or any part of them, and a sale, lease, mortgage, disposition, encumbrance, merger or consolidation made in contravention of this clause is void, but nothing in this clause shall be construed to prevent in any way the sale, lease, mortgage, disposition, encumbrance, merger or consolidation of any of the property of an owner of a public utility designated under subsection (1) in the ordinary course of the owner's business.

[Prohibited share transaction]

102(1) Unless authorized to do so by an order of the Board, the owner of a public utility designated under section 101(1) shall not sell or make or permit to be made on its books a transfer of any share of its capital stock to a corporation, however incorporated, if the sale or transfer, in itself or in connection with previous sales or transfers, would result in the vesting in that corporation of more than 50% of the outstanding capital stock of the owner of the public utility.

Interpretation Act, R.S.A. 2000, c. I-8

[Enactments remedial]

10 An enactment shall be construed as being remedial, and shall be given the fair, large and liberal construction and interpretation that best ensures the attainment of its objects.

Solicitors:

Solicitors for the appellant/respondent on cross-appeal: McLennan Ross, Calgary.

Solicitors for the respondent/appellant on cross-appeal: Bennett Jones, Calgary.

Solicitor for the intervener the Alberta Energy and Utilities Board: J. Richard McKee, Calgary.

Solicitor for the intervener the Ontario Energy Board: Ontario Energy Board, Toronto.

Solicitors for the intervener Enbridge Gas Distribution Inc.: Fraser Milner Casgrain, Toronto.

Solicitors for the intervener Union Gas Limited: Torys, Toronto.

* * * * *

Corrigendum, released April 24, 2006

Please note also the following change in *Atco Gas & Pipelines Ltd. v. Alberta (Energy Utilities Board)*, 2006 SCC 4, released February 9, 2006. In para. 8, line 3 of the English version, "s. 25.1(1)" should read "s. 25.1(2)".

7

RP-2005-0013
EB-2005-0031

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c.15 (Schedule B);

AND IN THE MATTER OF an Application by Great Lakes Power Limited for an order or orders approving or fixing just and reasonable rates.

BEFORE: Gordon Kaiser
Vice Chair and Presiding Member

Pamela Nowina
Vice Chair and Member

Paul Vlahos
Member

DECISION AND ORDER

This is the majority decision with reasons of Vice Chair Nowina and Board Member Vlahos. The minority reasons of Vice Chair Kaiser follow.

Background

On January 18, 2005, Great Lakes Power Limited ("GLP") submitted an application to the Ontario Energy Board for a distribution rate adjustment related to the recovery of the second interim tranche of regulatory assets pursuant to the Board's instructions found in the filing guidelines issued on December 20, 2004.

On February 16, 2005, Boniferro Mill Works Inc. ("Boniferro") submitted an intervention objecting to its classification as Larger Customer A and to its line loss rates.

On March 30, 2005, the Board issued a Decision and Interim Order approving distribution rate adjustments. In that decision, the Board declared GLP's rates interim effective April 1, 2005 and because of the outstanding matter relating to Boniferro, directed GLP to file written evidence with respect to the issues raised by Boniferro. The oral hearing focusing on Boniferro's issues was held on November 7 and 8, 2005 in the Board's hearing room in Toronto.

The rate classification that currently applies to Boniferro was first approved by the Board on an interim basis on May 13, 2002[1]. At that time, Domtar Wood Products was the distribution customer that owned the specific facilities at the site now owned by Boniferro at 45 Third Line West in Sault Ste. Marie. The interim decision approved the applied-for rates derived from the allocation of costs to proposed customer classes using the results of a study performed for GLP by Navigant Consulting Inc. The Navigant study classified Domtar as "Large Customer A", the only customer in that specific rate class. The basis for this classification was Domtar's unique demand, which was significantly higher than GLP's commercial customers in the General Service > 50 kW rate class, and significantly lower than GLP's largest distribution customer.

In December of 2002, GLP's interim rate order was made final as a result of Ontario Government legislation, Bill 210. By legislation, electricity distribution rates could only be altered with the permission of the Minister of Energy during the period December 2002 to January 2005.

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[1] RP-2002-0109/EB-2002-0249

According to the evidence, Domtar started to wind down its operations in January 2003. The hardwood sawmill did not operate in February and March of 2003. Boniferro took over the hardwood sawmill operations from Domtar on or about the end of March 2003 but Domtar remained the customer of GLP for 45 Third Line West until it exited the site at the end of October 2003. During that time, Boniferro was paying Domtar for part of the electricity bill issued to Domtar from GLP. During that period some consumption was always registered on the meter.

The evidence shows that Boniferro requested electricity service from GLP by letter dated March 24, 2003. In that letter Boniferro indicated its expectations that it would be charged under the General Service > 50 kW rate class and, if not so, to be notified. By response dated April 25, 2003, GLP indicated that it would be classifying Boniferro in the Large Customer A class, the same as Domtar, and provided the reasons for such classification.

By letter to GLP dated January 21, 2004, Boniferro expressed concerns regarding its classification as Large Customer A. In that letter, Boniferro noted that its November and December 2003 average monthly peak demand was 1,113 kW and 1,119 kW respectively and that its future peak demand is expected to be in this range.

Boniferro paid GLP on the basis of the Large Customer A rates until June 2004. Beginning in July 2004, Boniferro began to remit an amount which it calculated would be payable if Boniferro was in the General Service > 50 kW rate class.

In this proceeding, Boniferro argued that the Domtar Large Customer A rate was not applicable as this ‘site specific’ rate was not related to a site specific cost, that the results of the Navigant study were not fair to Boniferro and that Boniferro should be more appropriately placed in the General Service > 50 kW class.

GLP argued that Boniferro's operations were not significantly different from Domtar's and was opposed to the reclassification of Boniferro on that basis. GLP acknowledged that the Board never had the opportunity to scrutinize the distribution rate application which included the Navigant study as the initial interim rates were made final by Bill 210, and not as a result of a proceeding before the Board. However, GLP maintained that the study was based on standard cost allocation and rate making principles which involved the sharing of costs and subsidies among customer classes.

GLP offered to mitigate the Large Customer A rate by adjusting the allocators in the Navigant study by using the volumes reflecting Boniferro's operations in 2004. This would generate lower Large Customer A rates for Boniferro. GLP also requested that in the event the Board decided to adjust Boniferro's rates due to either a reclassification or GLP's scenario of mitigating the Large Customer A rate, that the Board grant an accounting order to establish a deferral account to record any deficiencies.

With regard to the loss factor issue, Boniferro submitted that in the event that the Board reclassified Boniferro to the General Service > 50 kW class, Boniferro would accept the current line loss factor of 6.9%; otherwise it requested that GLP justify the 6.9% figure as applicable to the Large Customer A class.

GLP submitted that it did not specifically assign a unique loss factor to the Large Customer A class as a result of the specific classification found in the Navigant study. It noted that the currently applied loss factor is appropriate for Boniferro since it was calculated in accordance with the Board's formula for primary metered customers as set out in the Board's Retail Settlement Code. GLP also noted that the current loss factor is lower than the actual recorded loss factors currently experienced in the GLP system.

Board Findings

All panel members agree on the rate classification for Boniferro from April 1, 2005, when the rates became interim. There is disagreement on the appropriate treatment of the period before this. These are the findings of the majority.

The first issue to be dealt with is whether Boniferro should continue to be in the Large Customer A classification. We find that it should not.

GLP's General Service >50 kW rate class does not contain a maximum threshold. GLP's Large Customer A classification does not state a minimum or maximum threshold. This is the first opportunity for the Board to review the reasonableness of the establishment of GLP's Large Customer A Classification.

GLP's alternative solution in this proceeding, to revise the cost allocation by using the Boniferro loads from 2004, does provide some relief to Boniferro, as the costs assigned to the Large Customer A classification are based on monthly peak loads. However, this does not address the issue of the appropriateness of the Navigant study regarding classification in the first instance. We are not persuaded on the evidence in this proceeding that it is appropriate that one customer should make up a single rate class, especially as there was no direct assignment of costs to the Large Customer A class, only an allocation based on customer loads.

Establishing a single customer class is unusual, and there must be sufficient evidence to demonstrate why it is appropriate for a particular customer to have a unique rate. Although the Board had enough evidence before it to review the rate classification dispute between the two parties, this proceeding was not the forum to specifically address the Navigant study's rationale and methodology. The Board determined that it would review evidence on the issues raised by Boniferro in its intervention of GLP's application, within the context of the 2005 rate adjustment process. The generic Notice issued by the Board for the 2005 rates proceeding limited the scope of the proceeding to a rate adjustment based on changes reflecting (in GLP's case) the next interim instalment of the four year recovery of distributors' regulatory assets.

Intervenors are not limited to addressing issues brought forth by an Applicant. Therefore, the Board was willing to review the issues brought forth by Boniferro, namely their alleged misclassification. Although the Board did not ask for evidence on the Navigant Study itself, GLP had notice that the appropriateness of the Large Customer A rate would have been an issue. However, GLP did not provide sufficient evidence in our view to justify a continuation of the site specific rate for 45 Third Line West in Sault Ste. Marie.

We therefore find that Boniferro should be reclassified to the General Service > 50 kW class. The option remains open for GLP to propose otherwise based on a new study, or a review of the Navigant Study, which would demonstrate that Boniferro, as the occupant of 45 Third Line West in Sault Ste. Marie, should be assigned to a different rate class than the General Service > 50 kW class.

The second issue is the effective date of the reclassification. We find that the reclassification will be retroactive to the date interim rates were set – April 1, 2005. Boniferro's classification will not be changed for the period prior to April 1, 2005.

GLP's rates were approved by the Board on an interim basis by way of an interim order dated May 13, 2002, in the same way as all other electricity distributors in the province received approval for interim rates. By legislation (Bill 210), interim rate orders fixing rates under s. 78 of the *Ontario Energy Board Act*, *1998* for electricity distributors were made final. During the period of the rate freeze (December 2002 to January 2005), applications to the Board for rate changes were permitted only with the leave of the Minister of Energy. The Board had not received authority from the Minister to deal with this matter. Therefore, the Board was not able to review the reasonableness of GLP's rate classification prior to this proceeding.

Bill 210 made the interim GLP rate order a final rate order. Therefore we are of the view that changing rates prior to April 1, 2005 would be retroactive ratemaking. As the Board has stated in numerous cases, the Board does not endorse retroactive ratemaking. The Board must be mindful of the negative implications of retroactive rates. When investors and consumers cannot be assured that final rates are indeed final, the resultant risks increases costs for everyone. In addition, intergenerational inequities arise, with today's consumers paying the costs of past events. In this case, it is not appropriate for either the utility or its ratepayers to bear the implications of a retroactive rate change. To burden the utility would be contrary to the regulatory compact. To burden the ratepayers would be wrong, especially given the length of the retroactivity.

We are also of the view that the Board is limited in its decision by legal precedent. The Supreme Court of Canada has ruled on the issue of retroactive ratemaking.

In 1989, Bell Canada appealed a decision[2] of the CRTC which retroactively altered an interim rate that had previously been approved by the CRTC. The Court held that:

> It is inherent in the nature of interim orders that their effect as well as any discrepancy between the interim order and the final order may be reviewed and remedied by the final order. […] It is the interim nature of the order which makes it subject to further retrospective directions.

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2 *Bell Canada v. Canada (Canadian Radio-Television and Telecommunications Commission)* [1989] 1 S.C.R. 1722

However, with regard to the status of final orders the Court stated that:

> [a] consideration of the nature of interim orders and the circumstances under which they are granted further explains and justifies their being, unlike a final decision, subject to retrospective review and remedial orders.

The Supreme Court re-iterated its position on retroactive rate-making in the ATCO decision[3]. Speaking for the majority, Mr. Justice Bastarache noted:

> [i]t is well established throughout the various provinces that utilities boards do not have the authority to retroactively change rates.

A decision of the Alberta Court of Appeal[4] also makes findings regarding retroactive rates. The Court found that:

> A fundamental principle of statutory interpretation is that retrospective power can only be granted through clear legislative language. This principle is based on notions of fairness and the reliability of expectations.

The *Ontario Energy Board Act, 1998* does not contain any provisions that deal specifically with retroactive ratemaking, and the Board is therefore not empowered to alter a final rate order retroactively. Furthermore, the Act requires that balances in deferral accounts should be reviewed by the Board at least annually. We infer from this that there is a policy against adverse impacts and inter-generational inequity that might be caused by out-of-period rate adjustments.

Therefore, for the above reasons, we find that GLP has had a valid order to charge the rates that it has charged to Boniferro for electricity consumption up to March 31, 2005. For consumption on and after April 1, 2005, however, GLP shall

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[3] *ATCO Gas & Pipelines Ltd. v. Alberta (Energy & Utilities Board),* [2006] S.C.C. No. 4

[4] *Beau Canada Exploration Ltd. v. Alberta (Energy and Utilities Board)* [2000] A.J. No. 507 (C.A.)

classify and invoice Boniferro on the basis of the General Service > 50 kW rate classification.

Having made the above findings, whether GLP erred or acted unreasonably by not placing Boniferro in the General Service > 50 kW rate class at the time Boniferro became a customer of GLP is not determinative. However, it became a focal point in the proceeding and we feel that we must comment on it. We conclude that GLP did not err or act unreasonably.

The essence of Bonifero's argument is that it should not have been classified as Large Customer A since it never accepted such classification. It argues that once Domtar exited the business, the revenue associated with the Large Customer A class disappeared and Boniferro should have been classified as a completely new customer, different from Domtar.

GLP had established and received Board approval for a rate classification based on a single customer, Domtar Wood Products. However, the rate classification described Large Customer A as the customer located at 45 Third Line West in Sault Ste. Marie and did not specifically name Domtar Wood Products. That classification was put in place at the time GLP had to unbundle its rates to conform with the Board's directions to all the electricity distributors in the province and was derived from the Navigant study. Domtar did not intervene in GLP's application at that time.

It is reasonable to expect that GLP would treat Boniferro the same as the previous owner of the site. It was the same property as Domtar's, the same distribution assets, and essentially the same business as Domtar's, served under the same meter. When Boniferro acquired certain assets from Domtar in 2003 and Boniferro replaced Domtar as the customer of GLP, Boniferro was properly assigned in our view the rate classification that applied to Domtar. The fact that the hardwood sawmill operations ceased for a period of two months does not alter the fact that without experience as to what the changes, if any, would be to the monthly peak demand level of electricity, it would not be reasonable to expect GLP to assign Boniferro to a different classification at that time.

As a utility, GLP has a responsibility to act in a prudent fashion for all its customers. Changing the classification of an existing property without evidence of significant peak demand consumption patterns, would not be consistent with the utility's obligation to other customers who would, in the future, be required to pick up the shortfall.

Mr. Boniferro acknowledged that, prior to continuing his business as a customer of GLP, his assumption of 750 to 800 kW peak demand was his own. He neither received expert advice in forming that assumption, nor did he receive any indication from GLP that his business would be served under the General Service > 50 kW rate class. On the contrary, GLP had informed Boniferro in its response letter of April 25, 2003 that Boniferro would be billed under the same classification as Domtar. Mr. Reid, testifying on behalf of Boniferro, acknowledged that it is difficult to come up with a forecast for peak demand prior to operating a company like Boniferro. As it turned out, Boniferro's average of its 2005 monthly peak demands as of August 2005 was 1,556 kW or 15% lower than the average of Domtar's monthly peak demands in 2000.

For the above reasons, we are of the view that GLP acted reasonably in classifying Boniferro in the Large Customer A classification, replacing Domtar.

Also, by way of context, the Board was first notified of this dispute in October 2004 by way of a complaint lodged by Boniferro to the Board's Compliance Office. The Chief Compliance Officer, in a letter to Boniferro dated February 2005, found no violation of the rate order by GLP. Furthermore, in a letter to GLP dated April 27, 2005 in the context of the instant rates proceeding, the Board stated that, "The Board is of the view that this issue is not about GLPL's compliance with its rate order but rather as to what is an appropriate rate for Boniferro going forward.”

Boniferro’s objection to be in the Large Customer A classification does not invalidate an existing Board rate order containing such classification.

The final issue relates to the treatment of GLP’s forgone revenues resulting from the reclassification.

GLP requested that a deferral account be established to track underpayments or under recoveries of revenues as a result of this decision. The Board finds that a deferral account should be established by GLP to record the difference in revenue resulting from classifying Boniferro as a General Service > 50 kW customer effective April 1, 2005. These amounts should be considered in a future rates proceeding. The methodology used to dispose of these amounts will be determined at that time.

With respect to GLP’s shortfall in revenue in the period July 2004 to March 2005, during which Boniferro was not paying GLP the invoiced amounts, it is the view of the Board that this a private collection matter between GLP and Boniferro. The Board found that the rate order was valid in this period and neither the utility nor its ratepayers should be burdened with retroactive ratemaking. However, the Board expects that GLP will exercise prudence in this regard so that it and its customers will continue to benefit from a future revenue stream and from continuing to utilize its distribution assets (no stranded assets) by having Boniferro as a customer.

We note Boniferro’s position that if it were to be classified as a General Service > 50 kW customer, it would accept the 6.9% loss factor applied by GLP to that rate class. We find that that there should be no change to the previously approved 6.9% loss factor.

Therefore, the Board orders that:

1. GLP classify Boniferro as a customer in the General Service > 50 kW rate class, effective April 1, 2005.

2. GLP establish a deferral account to capture any revenue deficiency from Boniferro being classified as a General Service > 50 kW rate class customer from April 1, 2005.

DATED at Toronto, February 24, 2006

Original signed by

Pamela Nowina
Vice Chair and Member

Original signed by

Paul Vlahos
Member

MINORITY REASONS

These are the minority reasons of Vice Chair Kaiser.

This proceeding relates to a billing dispute between Great Lakes Power Ltd. ("GLP" or the "utility") and its customer, Boniferro Millworks Inc. ("Boniferro"). GLP has classified Boniferro in the Large Customer A category. Boniferro argues that it should be more properly classified as a General Service > 50 kW customer. This would result in a 25% reduction of the cost of electricity to Boniferro.

The evidence indicates that Boniferro at all times rejected this classification but for a period of time (November 2003 to June 2004) did pay the larger rate. However, since July 1, 2004 Boniferro has been paying at the lower rate under the General Service > 50 kW class. GLP argues that the customer has been underpaying and substantial monies are owed. Boniferro on the other hand, argues that if anything it has been overpaying.

This dispute came before the Board through an intervention by Boniferro in the general rate application filed by GLP on January 18, 2005. Further to the filing of the intervention by Boniferro on February 16th the Board issued various Procedural Orders which provided for interrogatories and the filing of evidence. The Board held an oral hearing in this matter on November 7th and 8th, 2005.

The rate order at issue in this case is somewhat unique. GLP's 2002 rate application was approved by the Ontario Energy Board on an interim basis on May 13, 2002, with rates made effective May 1, 2002. In December of 2002, this interim rate order was made final as a result of Ontario Government legislation, Bill 210. This final rate order set out a Large Customer A rate. While this is referred to as a rate class it in fact included only one customer and was designed specifically for that customer. The rate was set for Domtar Wood Products and was based on the analysis performed by Navagant Consulting in a detailed cost allocation study.

In March 2003, Boniferro purchased part of the Domtar property and changed its operations. Boniferro did not assume or enter into any supply agreement with GLP and did not assume any agreements between GLP and Domtar. In November 2003, Domtar ceased all operations on the property and Boniferro was required to make its own arrangements with GLP.

When Boniferro acquired certain assets from Domtar, GLP assigned Boniferro to the Large Customer A class and began to charge distribution rates applicable to that class. Boniferro objected on the grounds that its usage was not the same as Domtar and that no cost allocation study had been done with respect to its usage.

GLP argued that the rate was “site specific” and that Boniferro was required to pay the rate.

The concept of a “site specific” rate is an unusual one. Rates are generally determined between customer classes on the basis of usage. Here there was no analysis of the usage, rather just a declaration that the rate was site specific. Moreover, this is really not a rate class; it was a one customer rate that was designed specifically for another customer.

It is clear that there were fundamental changes in the operation of Boniferro compared to the previous owner of the land, Domtar Wood Products. First, only part of the property was purchased from Domtar and second, detailed evidence was presented by the president of Boniferro as to the changed functionality. Counsel for GLP admitted in argument that in 2004 the average monthly peak demand for Boniferro was approximately 1,400 kW which was around 24% less than the 1,831 kW that was used for the purpose of creating a Large Customer A class in the first place.

Aside from the reduced electricity use by Boniferro, evidence was presented by Boniferro that indicated that GLP was requiring Boniferro to bear an excessive cost burden. Boniferro pointed to the fact that the dedicated facilities used to serve their plant consisted of 3.65 km of line which at its brand new installed cost, as opposed to the current depreciated cost, was only $250,000. Notwithstanding that, Boniferro was allocated close to $1 million in system costs which they say did not relate to the cost of serving Boniferro.

Boniferro wants to pay the General Service > 50 kW rate from the date service commenced in November 2003. They would accordingly recover the amounts which they overpaid for a period of eight months. The majority hearing this case concluded that the lower rate can go into effect only on April 1, 2005 because to do otherwise would constitute retroactive rate-making. I disagree. This is not a case of retroactive rate-making. This is an error in customer classification.

Retroactivity

There are a number of reasons why the retroactivity issue does not arise in this case. First, there is good reason to believe that the Domtar rate disappeared. While the Domtar rate is called the Large Customer A class, it’s a class in name only. It was designed for a specific customer and was based on a cost allocation study that related solely to that customer. It is argued by Boniferro that when Domtar ceased operations that rate order disappeared. If the rate order disappeared, there are no retroactive rates applying to that rate order.

Second, even if the rate did not disappear, it was not meant to apply to Boniferro and should not have been applied to Boniferro. Boniferro should not have been put in that rate class; rather, it should have been put in the General Service > 50 kW rate class. It is true that the utility classified Boniferro in this rate class during a period where the utility's rates were deemed to be a final order by legislation. But this does not mean that this classification was correct or that Boniferro should bear the costs of this classification. Does the rule against retroactive rate making mean that Boniferro should bear these costs? It is not Boniferro's fault that this matter has taken this long to resolve. Boniferro has been complaining about misclassification since the very beginning. Put differently, there is an unjust enrichment when a customer has paid a rate which does not apply to that customer, and the Board may remedy that by ordering a refund. The test for unjust enrichment was recently addressed by the Supreme Court of Canada[5]. Iacobucci J. stated the test for unjust enrichment for the Court, as follows:

> As a general matter, the test for unjust enrichment is well established in Canada. The cause of action has three elements: (1) an enrichment of the defendant; (2) a corresponding deprivation of the plaintiff; and (3) an absence of juristic reasons for the enrichment. (Paragraph 30)

The *Garland* case is particularly relevant because it addressed the payment of utility rates. In that case, the Court applied an earlier finding that the interest rate on outstanding utility bills was unlawful in the context of the test for unjust enrichment. In applying that test, the Court had no trouble finding that the utility was enriched and the rate payer was deprived. The real issue there, as well as here, was whether there was a juristic reason for the enrichment. There, as here, the utility argued that the enrichment had a juristic justification because it was authorized by a Board Order. The Court, who found that the order was unlawful and therefore inoperative, held that the order could not be relied upon as a juristic reason for the enrichment. According to the Court:

> As a result, the question of whether the statutory framework can serve as a juristic reason depends on whether the provision is held to be inoperative. (Paragraph 51)

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5 *Garland v. Consumers' Gas Co.,* [2004] 1 S.C.R. 629.

Thus, because the provision was inoperative, the Court ordered that the payment be refunded. I believe that this is the appropriate context to consider the relevance of retroactive rate making.

No one disputes that retroactive rate-making is improper. This is most recently recognized by the Supreme Court of Canada in the ATCO decision and numerous decisions before[6]. In *Northwestern Utilities Ltd. v. City of Edmonton*, Estey J. stated on page 691:

> It's clear from the many provisions of *The Gas Utilities Act* that the Board must act prospectively and may not award rates which will recover expenses incurred in the past and not recovered from rates established for past periods.

The general principle is that when a Board establishes a Final Order with respect to rates, that rate is in effect until replaced, i.e. the final rate either is replaced by an Interim Rate or is replaced by a new Final Rate Order in a subsequent proceeding. The reason is that the regulatory compact assumes that between rate hearings, there will always be over earnings or under earnings but the utility must accept the consequences. It is not entitled to be reimbursed if it does not make its full allowed rate of return. On the other hand, the utility does not have to give money back to the ratepayers if it earns in excess of that amount. Rates are to be corrected at the time of the next hearing on a going forward basis. They are not made retroactive. This allows the utility to finance its operations on a predictable basis and provides finality to proceedings.

As a result, if the rate was properly applicable to Boniferro during the entire period, then, under the unjust enrichment doctrine, the rate would be operative.

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[6] *Northwestern Utilities Ltd. v. City of Edmonton*, [1979], 1 S.C.R. 684; *Re Coseka Resources Ltd. and Saratoga Processing Co.* (1981), 126 D.L.R. (3d) 705, leave to appeal refused, [1981] 2 S.C.R. vii; *Re Dow Chemical* Canada *Inc. and Union Gas Ltd.* (1982), 141 D.L.R. (3d) 641, aff'd (1983), 42 O.R. (2d) 731

As a result, there would be a juristic reason for the utility's enrichment, i.e., the enrichment would not be unjust. Furthermore, given the rule against retroactive rate making, the Board could not now amend that rate to cover a previous period. However, this is not the case here. I am not proposing that the rate be changed; I am finding that it did not apply. The rate was not operative as applied to Boniferro. It therefore does not constitute a juristic reason for the enrichment.

The prohibition against retroactivity assumes that a Final Order has been made by the Board and properly applies to the customer at issue. Here, the Board did not make these rates final as applied to that customer. The customer's inability to challenge the applicability of the rate occurred through a legislative "accident" when the legislature enacted Bill 210. It's hard to argue that the intent of Bill 210 was to create a final order that prohibited a customer from obtaining relief in an ongoing dispute regarding customer classification.

Fundamentally, this case is about customer misclassification. Boniferro applied for service on the basis that it was in the General Service > 50 kW category. That was rejected and the utility placed them in a unique Domtar category called Large Customer A. This dispute has continued on the basis of that alleged misclassification.

The application of the retroactivity doctrine to this case assumes that the Board is adjusting the Domtar or Large Customer A rate retroactively. That with respect is not the issue. Boniferro has never asked for that relief. Rather, Boniferro has asked to be placed in the proper customer classification and to have that take effect from the date service commenced.

In the circumstances, throughout the period starting November 2003, Boniferro should be paying the applicable rates of the General Service > 50 kW class.

It is also important that considerable evidence has been placed before the Board as to the financial difficulties facing Boniferro in its current operations. The over payment at issue is a serious matter for this particular customer. The utility needs to remain prudent that it not arbitrarily determine rates that would lead to the disappearance of the customer and to stranded assets. That will generate a revenue deficiency much greater that that created by reclassification.

How is the deficiency recovered?

Under both the minority and majority decisions there will be a revenue deficiency for the utility. GLP's filing in the 2005 rate case was based on a revenue requirement that assumed that the customer in the Large Customer A class was properly classified and is paying that rate. In both the minority and majority decisions this is not the case. The difference is the length of period that the deficiency relates to.

The minority decision states that the misclassification took place at the beginning of service in November 2003 and the lower rate should prevail from that point. The majority decision states that the lower rate should be effective only from April 1, 2005 because a lower rate prior to that date amounts to retroactive rate-making.

The majority decision analyses the prudence of the utility in the initial classification and finds no fault. It is clear that Boniferro argues that the decision was an error and that they should not have been assigned the Domtar rate and certainly not without a proper cost allocation study. There is some support for that position in the record. There is evidence that the utility declared the rate “site specific” and failed to take into account the differences in functionality of the new operator. The utility admitted in argument that the usage of Boniferro was 24% less than the demand used in striking the Domtar rate.

The Board addressed the prudence test in its Decision in the Enbridge case regarding the prudence of the Alliance contracts[7].

The test is well known but its worth repeating in the context of these proceedings. The first principle is this; when a utility makes decisions in operating its business, the regulator assumes that those decisions, whether they relate to investments or otherwise, are prudent. In other words, there is a burden on those challenging the prudence to demonstrate, on reasonable grounds, that there has been a lack of prudence.

The second principle is that, in analysing whether the utility was prudent or not, the Board must look at the facts and circumstances that were known or ought to be known to the utility at the time the decision was made. In other words, hindsight should not be used to determine prudence.

Put differently, the utility's decision can turn out to be wrong but still have been prudent. Given the limited nature of the record before us and the presumption of prudence on the part of the utility, I find that the decision by the utility to classify Boniferro in the Large Customer A category was a prudent decision. That doesn't mean it was the right decision. In fact, it was the wrong decision.

However, the consequence of this finding is that the shareholder should not bear the deficiency which would result from the reclassification of the customer. The deficiency should be recovered from the other rate classes and the exact disposition of that can be dealt with by the Panel hearing that rate case. The deficiency may be recovered from all customer classes or it may be recovered only from the General Service > 50 kW class. A Procedural Order can be issued to deal with this issue. It's not unusual in rate cases that cost allocation issues between customers will arise and be dealt with by Panels hearing those cases.

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[7] Re: Enbridge, RP-2001-0032, Para. 3.12.2

Boniferro's remedy

Given the concern with retroactivity, I would order that Boniferro be classified in the General Service > 50 kW class from the date service commenced. The utility will be directed to provide a credit towards amounts to be paid by Boniferro in the future in an amount equal to the overpayment. The overpayment can be readily calculated and submissions can be made if necessary with respect to the accounting.

There is ample authority in the regulatory jurisprudence that credits going forward do not constitute retroactive rate-making.[8] This is particularly the case where it reflects a one time fixed amount adjustment to an overpayment that the tribunal finds unjust.

I would also order that the utility be directed to pay Boniferro's costs in this proceeding in an amount to be taxed in the usual fashion.

In summary, I agree with the majority that GLP should charge Boniferro the General Service > 50 kW rates and that the utility establish a deferral account to track any revenue deficiency that results. I disagree with the majority regarding the effective date of the reclassification. GLP should reclassify Boniferro to the General Service > 50 kW class as of the date which service commenced, November 2003. I also disagree with the majority regarding the effective date of the deferral account. The deferral account should track any revenue deficiency as of November 2003 and the disposition of these amounts should be considered by the Panel hearing the 2006 rate case. The allocation as between different customer classes can be determined at that time.

[8] N*ew York Water Service Corp. v. Public Service Commission*, 208 N.Y. S. 2d 587 (1960). In that case, a utility commission ruled that gains on the sale of real estate should be taken into account to reduce rates annually over the following period of 17 years (p.864). The regulator's order was upheld by the New York State Supreme Court (Appellate Division). See also *ATCO Gas and Pipelines Ltd v. Alberta Energy and Utilities Board* [2006] S.C.J. 4 at Para. 137.

DATED at Toronto, February 24, 2006

Original signed by

Gordon Kaiser
Vice Chair and Presiding Member

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Indexed as:

Northwestern Utilities Ltd. v. Edmonton (City)

Northwestern Utilities Limited and The Public Utilities Board of the Province of Alberta, Appellants; and The City of Edmonton, Respondent.

[1979] 1 S.C.R. 684

[1979] 1 R.C.S. 684

Supreme Court of Canada

1977: November 28 / 1978: October 3.

Present: Laskin C.J. and Ritchie, Spence, Pigeon, Dickson, Estey and Pratte JJ.

ON APPEAL FROM THE SUPREME COURT OF ALBERTA, APPELLATE DIVISION

Public utilities -- Application for interim rate increase -- Order of Public Utilities Board permitting recovery of losses incurred before date of application -- Board thereby offending provisions of s. 31 of The Gas Utilities Act, R.S.A. 1970, c. 158 -- Application of s. 8 of The Administrative Procedures Act, R.S.A. 1970, c. 2, to proceedings -- Matter returned to Board for continuation of hearing.

Commencing on August 20, 1974, the appellant company filed an application with the Alberta Public Utilities Board for an order determining the rate base and fixing a fair return thereon and approving the rates and charges for the natural gas supplied by the company to its customers. The application made reference to the powers under s. 31 of The Gas Utilities Act, R.S.A. 1970, c. 158, by asking for an order "giving effect to such put of any losses incurred by the applicant as may be due to any undue delay in the hearing and determining of the application". Finally the application sought an order fixing interim rates pending the establishment of "final rates". As a result of this application several interim orders were issued between November 15, 1974, and June 30, 1975. In response to the application of August 20, 1974, the Board by order made on September 15, 1975, established the rate base, a fair return thereon and the total utility requirement at $72,141,000. These items were respectively found and included in the order on the basis of "actual 1974" figures and "forecast 1975" figures. The Board then directed the company to file a schedule of rates "designed to generate the foregoing total utility revenue requirements approved by the Board".

On August 20, 1975, the company filed with the Board an application for an order "approving changes in existing rates, tolls or charges for gas supplied and services rendered by [the company] to its customers"; and on September 25, 1975, it filed an application for an interim order "approving changes in existing rates, tolls or charges for gas supplied and services rendered by [the company] to its customers pending final determination of the matter". The application of 1975 recited the history of the 1974 application and stated that the operating costs and gas costs of the company "have increased substantially over the amounts included in the 1974 application and continue to increase". After reciting that the Board in response to the 1974 application has awarded the applicant "interim refundable rates", the 1975 application went on to state that the "existing rates charged by the applicant for natural gas do produce revenues sufficient to provide for its present or prospective proper operating and depreciation expense and a fair return on the property used in the service to the public". Therefore the company went on to apply for an order determining the rate base, and a fair return thereon, and fixing and approving rates for natural gas supplied by the company to its customers. The company sought as well an order giving effect to "such part of any losses incurred by the applicant as may be due to any undue delay in the hearing and determining of application". The 1975 application sought as well interim rates "pending the fixing of final rates".

By its order of October 1, 1975, the Board granted an interim increase in rates the effect of which was to allow the company to receive $2,785,000 in excess of its revenues for 1975 which would have been received under the then existing rates. The City of Edmonton appealed from this interim order to the Appellate Division of the Supreme Court of Alberta pursuant to s. 62 of Public Utilities Board Act, R.S.A. 1970, c. 302. The majority of the Appellate Division set aside the order and remitted it to the Board for reconsideration on two grounds: (1) that the effect of the order was a contravention of s. 31 of The Gas Utilities Act in that the company was thereby granted recovery of losses incurred before the date of application, namely, August 20, 1975; and (2) that the Board failed to comply with s. 8 of The Administrative Procedures Act, R.S.A. 1970 c. 2, by reason of its failure to give reasons for its decision. The company and the Board appealed to this Court from the decision of the Appellate Division.

Held: The appeal should be dismissed and the matter returned to The Public Utilities Board for continuation of the hearing of the company's application of August 20, 1975.

The word "losses" as it is employed in s. 31 does not refer to accounting losses in the sense of a net loss occurring in a defined fiscal period but rather refers to the loss of revenue suffered by a utility during a defined period by reason of the delay in the imposition during that period of the proposed increased rates.

The first of the two principal issues in this appeal, i.e., whether the Board by its interim order of October 1, 1975, offended the provisions of s. 31 by granting as alleged by the City an order permitting the recovery of losses incurred before the date of the application, August 20, 1975, was very narrow. The issue was simply whether or not the company by not applying in the 1974 application for a further interim order caused the Board to respond to the new application in 1975 in such a way as to authorize a new tariff which when implemented by the company will have the effect of recovering from future gas consumers revenue losses incurred by the company with respect to gas deliveries made to consumers prior to the date of the application in question (August 20, 1975) or prior to the advent of the October 1, 1975, rates in a manner not authorized by s. 31.

The majority in the Court below observed that "prima facie the new tentative rate base includes an amount for revenue losses in 1975 up to the date of the application in August, since the figures do not purport to apportion the loss between the two periods of the year". This Court was not prepared to say that a prima facie case had been established that the effect of the application of the interim rates from October 1, 1975, onwards will be the recovery in the future of revenue shortfalls incurred prior to August 20, 1975. The test was not whether the new tentative rate base includes an amount for revenue losses" but rather the question was whether or not the interim rates prospectively applied will produce an amount in excess of the estimated total revenue requirements for the same period of the utility by reason of the inclusion in the computation of those future requirements of revenue shortfalls which have occurred prior to the date of the application in question, whether or not those "shortfalls" have been somehow incorporated into the rate base or have been included in the operating expenses forecast for the period in which the new interim rates will be applied, subject always to the Board's limited power under s. 31.

The company submitted that a determination of what is or is not a 'past loss' is a pure question of fact and as such is not subject to appeal by reason of s. 62 of The Public Utilities Board Act, which limits appeals from Board decisions to questions of "law or jurisdiction". The appeal before this Court involved a determination of the intent of the Legislature with respect to the Board's jurisdiction to take into account shortfalls in revenue or excess expenditures occurring or properly allocable to a period of time prior to an application for the establishment of rates under the Act. The Board's decision as to characterization of "the forecast revenue deficiency in the 1975 future test year" of the company involved a determination of the matters of which cognizance may be taken by the Board in setting rates under the statute. This is a question of law and may properly be made the subject of an appeal to a court pursuant to s. 62. The disposition of an application which involved the Board in construing ss. 28 and 31 of The Gas Utilities Act raises a question of law and may well go to the jurisdiction of the Board.

However, it was not possible for the reviewing tribunal in the circumstances in this proceeding to ascertain from the Board's order whether the Board acted within or outside the ambit of its statutory authority. The form and content of the Board's order were so narrow in scope and of such extraordinary brevity that one was left without guidance as to the basis upon which the rates had been established for the period October 1, 1975, onwards. Hence this submission of the company failed.

As to the second issue, namely the application to these proceedings of s. 8 of The Administrative Procedures Act, which provision imposes upon certain administrative tribunals the obligation of providing the parties to its proceedings with a written statement of its decision and the facts upon which the decision is based and the reasons for it, the Board in its decision allowing the interim rate increase failed to meet the requirements of this section. The failure of the Board to perform its function under s. 8 included most seriously a failure to set out "the findings of fact upon which it based its decision" so that the parties and a reviewing tribunal were unable to determine whether or not in discharging its functions, the Board had remained within or had transgressed the boundaries of its jurisdiction established by its parent statute. The appellants were not assisted by the decision in Dome Petroleum Ltd. v. Public Utilities Board (Alberta) and Canadian Superior Oil Ltd. (1976), 2 A.R. 453, aff'd [1977] 2 S.C.R. 822, to the effect that under s. 8 of The Administrative Procedures Act the reasons must be proper, adequate and intelligible, and must enable the person concerned to assess whether he has grounds of appeal. Nor could the Board rely on the peculiar nature of the order in this case, being an interim order with the amounts payable thereunder perhaps being refundable at some later date, to deny the obligation to give reasons. The order of the Board revealed only conclusions without any hint of the reasoning process which led thereto. The result was that a reviewing tribunal could not with any assurance determine that the statutory mandates bearing upon the Board's process had been heeded.

As for the participation of The Public Utilities Board in these proceedings, there is no doubt that s. 65 of The Public Utilities Board Act confers upon the Board the right to participate on appeals from its decisions, but in the absence of a clear expression of intention on the part of the Legislature, this right is a limited one. The Board is given locus standi as a participant in the nature of an amicus curiae but not as a party. That this is so is made evident by s. 63(2) under which a distinction is drawn between "parties" who seek to appeal a decision of the Board or were represented before the Board, and the Board itself.

The policy of this Court is to limit the role of an administrative tribunal whose decision is at issue before the Court, even where the right to appear is given by statute, to an explanatory role with reference to the record before the Board and to the making of representations relating to jurisdiction.

Cases Cited

Gill Lumber Chipman (1973) Ltd. v. United Brotherhood of Carpenters and Joiners of America Local 2142 (1973), 7 N.B.R. (2d) 41; MacDonald v. The Queen (1976), 29 C.C.C. (2d) 257; Re Canada Metal Co. Ltd. et al. and MacFarlane (1973), 1 O.R. (2d) 577; Labour Relations Board of the Province of New Brunswick v. Eastern Bakeries Ltd., [1961] S.C.R. 72; Labour Relations Board of Saskatchewan v. Dominion Fire Brick and Clay Products Ltd., [1947] S.C.R. 336; International Association of Machinists v. Genaire Ltd. and Ontario Labour Relations Board (1958), 18 D.L.R. (2d) 588; Central Broadcasting Co. Ltd. v. Canada Labour Relations Board and International Brotherhood of Electrical Workers. Local Union No. 529, [1977] 2 S.C.R. 112; Canada Labour Relations Board v. Transair Ltd. et al., [1977] 1 S.C.R. 772, referred to.

APPEAL from a judgment of the Supreme Court of Alberta, Appellate Division [(1977), 2 A.R. 317.], setting aside an order of The Public Utilities Board of the Province of Alberta granting an interim increase in rates pursuant to s. 52(2) of The Public Utilities Board Act, R.S.A. 1970, c. 302. Appeal dismissed.

T. Mayson, Q.C., for the appellant Northwestern Utilities Ltd.
W.J. Major, Q.C., and C.K. Sheard, for the appellant Public Utilities Board of the Province of Alberta.
M.H. Patterson, Q.C., for the respondent.

Solicitors for the appellant, The Public Utilities Board for the Province of Alberta: Major, Caron & Co., Calgary.
Solicitors for the appellant, Northwestern Utilities Ltd.: Milner & Steer, Edmonton.
Solicitor for the respondent, The City of Edmonton: M.H. Patterson, Calgary.

The judgment of the Court was delivered by

ESTEY J.:-- This is an appeal by The Public Utilities Board for the Province of Alberta and Northwestern Utilities Limited from a decision of the Appellate Division of the Supreme Court setting aside an order of the Board granting an interim increase in rates pursuant to s. 52(2) of The Public Utilities Board Act, R.S.A. 1970, c. 302.

The majority of the Court of Appeal set aside the order and remitted it to the Board for reconsideration on two grounds:

(1) That the effect of the order was a contravention of s. 31 of The Gas Utilities Act, R.S.A. 1970, c. 158, in that Northwestern Utilities Limited was thereby granted recovery of losses incurred before the date of application, namely, the 20th of August 1975; and
(2) That the Board failed to comply with s. 8 of The Administrative Procedures Act, R.S.A. 1970, c. 2, by reason of its failure to give reasons for its decision.

The appellant, The Public Utilities Board (herein referred to as 'the Board'), is constituted under The Public Utilities Board Act to "deal with public utilities and the owners thereof as provided in this Act" (s. 28(1)), and is given more specific duties and powers with respect to gas utilities under The Gas Utilities Act. The appellant, Northwestern Utilities Limited (herein referred to as 'the Company'), is a gas utility regulated under these statutes:

The Board is by the latter statute directed to "fix just and reasonable ... rates, ... tolls or charges ..." which shall be imposed by the Company and other gas utilities and in connection therewith shall establish such depreciation and other accounting procedures as well as "standards, classifications [and] regulations ..." for the service of the community by the gas utilities (s. 27, The Gas Utilities Act). In the establishment of these rates and charges, the Board is directed by s. 28 of the statute to "determine a rate base" and to "fix a fair return thereon". The Board then estimates the total operating expenses incurred in operating the utility for the period in question. The total of these two quantities is the 'total revenue requirement' of the utility during a defined period. A rate or tariff of rates is then struck which in a defined prospective period will produce the total revenue requirement. The whole process is simply one of matching the anticipated revenue to be produced by the newly authorized future rates to future expenses of all kinds. Because such a matching process requires comparisons and estimates, a period in time must be used for analysis of past results and future estimates alike. The fiscal year of the utility is generally found to be a convenient but not a mandatory period for these purposes. It is a process based on estimates of future expenses and future revenues. Both according to the evidence fluctuate seasonally and both vary according to many uncontrollable forces such as weather variations, cost of money, wage rate settlements and many other factors. Thus the rate when finally established will be such as the Board deems just and reasonable to allow the recovery of the expenses incurred by a utility in supplying gas to its customers, together with a fair return on the investment devoted to the enterprise. We are here concerned only with the rate establishing process and, hence, this summation of the Board's functions and powers is limited to that aspect of its statutory operations.

While the statute does not precisely so state, the general pattern of its directing and empowering provisions is phrased in prospective terms. Apart from s. 31 there is nothing in the Act to indicate any power in the Board to establish rates retrospectively in the sense of enabling the utility to recover a loss of any kind which crystallized prior to the date of the application (vide City of Edmonton et al. v. Northwestern Utilities Limited [[1961] S.C.R. 392.], per Locke J. at pp. 401, 402).

The rate-fixing process was described before this Court by the Board as follows:

> The PUB approves or fixes utility rates which are estimated to cover expenses plus yield the utility a fair return or profit. This function is generally performed in two phases. In Phase I the PUB determines the rate base, that is the amount of money which has been invested by the company in the property, plant and equipment plus an allowance for necessary working capital all of which must be determined as being necessary to provide the utility service. The revenue required to pay all reasonable operating expenses plus provide a fair return to the utility on its rate base is also determined in Phase I. The total of the operating expenses plus the return is called the revenue requirement. In Phase II rates are set, which, under normal temperature conditions are expected to produce the estimates of "forecast revenue requirement". These rates will remain in effect until changed as the result of a further application or complaint or the Board's initiative. Also in Phase II existing interim rates may be confirmed or reduced and if reduced a refund is ordered.

The statutory pattern is founded upon the concept of the establishment of rates in futuro for the recovery of the total forecast revenue requirement of the utility as determined by the Board. The establishment of the rates is thus a matching process whereby forecast revenues under the proposed rates will match the total revenue requirement of the utility. It is clear from many provisions of The Gas Utilities Act that the Board must act prospectively and may not award rates which will recover expenses incurred in the past and not recovered under rates established for past periods. There are many provisions in the Act which make this clear and I take but one example, found in s. 35, which provides:

> (1) No change in any existing rates...shall be made by a ... gas utility ... until such changed rates or new rates are approved by the Board.
> (2) Upon approval, the changed rates ... come into force on a date to be fixed by the Board and the Board may either upon written complaint or upon its own initiative herein determine whether the imposed increases, changes or alterations are just and reasonable.

Section 32 likewise refers to rates "to be imposed thereafter by a gas utility". The 1959 version of the legislation before the Court in this proceeding was examined by the Alberta Court of Appeal in City of Calgary and Home Oil Co. Ltd. v. Madison Natural Gas Co. Ltd. and British American Utilities Ltd. [(1959), 19 D.L.R. (2d) 655.] wherein Johnson J.A. observed at p. 661:

> The powers of the Natural Gas Utilities Board have been quoted above and the Board's function was to determine "the just and reasonable price" or prices to be paid. It was to deal with rates prospectively and having done so, so far as that particular application is concerned, it ceased to have any further control. To give the Board retrospective control would require clear language and there is here a complete absence of any intention to so empower the Board.

Vide also Regina v. Board of Commissioners of Public Utilities (N.B.), Ex parte Moncton Utility Gas Ltd. [(1966), 60 D.L.R. (2d) 703.], at p. 710; Bradford Union v. Wilts [(1868), L.R. 3 Q.B. 604.], at p. 616.

There is but one exception in this statutory pattern and that is found in s. 31 which is critical in these proceedings. It is convenient to set it out in full.

> It is hereby declared that, in fixing just and reasonable rates, the Board may give effect to such part of any excess revenues received or losses incurred by an owner of a gas utility after an application has been made to the Board for the fixing of rates as the Board may determine has been due to undue delay in the hearing and determining of the application.

It should be noted that s. 31 has been amended by s. 5 of The Attorney General Statutes Amendment Act, 1977, 1977 (Alta.), c. 9, which received Royal Assent on May 18, 1977. However, s. 5(3) of that Act provides that s. 31 "as it stood immediately before the commencement of" s. 5 "... continues to apply to proceedings initiated ..." before May 18, 1977. Accordingly, this case stands to be determined in accordance with s. 31 as set out above.

The interpretative difficulties raised by s. 31 are manifold. For one thing, the word 'losses' which is not defined in the Act is employed with reference to the Board's power to establish rates with respect to the period after an application has been made and before the Board has fully disposed of the application by taking into account "excess revenues and losses" which the Board determines have been "due to undue delay in the hearing and determination of the application". It is in my view apparent once the statute is examined as a whole that 'losses' as the word is employed in s. 31 does not refer to accounting losses in the sense of a net loss occurring in a defined fiscal period but rather refers to the loss of revenue suffered by a utility during a defined period by reason of the delay in the imposition during that period of the proposed increased rates. The word in short is an abbreviation for 'lost revenue' which may indeed be suffered by a utility during a period when the utility is not in a net loss position in the accounting sense of that term. This Court had occasion to consider s. 31 collaterally in City of Edmonton et al. v. Northwestern Utilities Limited, supra. Locke J. writing on behalf of the whole Court on this point so interpreted and applied the word "losses" as it appears in this section.

Much of the difficulty encountered before the Board and again reflected in the judgment of the Court of Appeal has arisen by the use of the expression 'loss' sometimes to refer to a net loss for a period in the past and sometimes by applying the term to a shortfall of revenue in the sense in which I believe the Legislature uses the term in s. 31. This difficulty appears to have been obviated by the new s. 31 which is not now before the Court (vide The Attorney General Statutes Amendment Act, 1977, supra).

Section 52(2) of The Public Utilities Board Act should also be noted:

> The Board may, instead of making an order final in the first instance, make an interim order and reserve further direction, either for an adjourned hearing of the matter or for further application.

Section 54 provides in similar language the authority for the Board to make such interim orders ex parte. These interim orders are couched in the same terms as the final or basic orders establishing rates and tariffs and hence are likewise prospective.

Against this statutory background a brief outline of the historical facts of this proceeding and its origins bring the two issues now before the Court into sharper focus. Commencing on August 20, 1974, the Company filed an application for an order determining the rate base and fixing a fair return thereon and approving the rates and charges for the natural gas supplied by the Company to its customers. The application made reference to the powers under s. 31 by asking for an order "giving effect to such part of any losses incurred by the applicant as may be due to any undue delay in the hearing and determining of the application". Finally the application sought an order fixing interim rates pending the establishment of "final rates". As a result of this application several interim orders were issued between

November 15, 1974, and June 30, 1975. In response to the application of August 20, 1974, the Board by order made on September 15, 1975, established the rate base, a fair return thereon and the total utility revenue requirement at $72,141,000. These items were respectively found and included in the order on the basis of "actual 1974" figures and "forecast 1975" figures. The Board then directed the Company to file a schedule of rates "designed to generate the foregoing total utility revenue requirements approved by the Board".

The practice and terminology historically adopted by the Board in the discharge of its statutory functions are no doubt clear to the industry and to persons attending upon the Board in the discharge of its functions but leaves something to be desired in the sense that the terminology does not precisely fit that employed by the legislation to which reference has been made. It is clear, however, that in its order with respect to the August 1974 application, the Board has attempted to establish in the prospective sense those rates which the Company will require to enable it to carry on its business as a gas utility in the future and until such further and other rates are established by the Board. Had the Company then responded to the September 15 order by filing a proposed schedule of rates the Board would no doubt in completion of its statutory response to the August 1974 application by the Company have established the appropriate schedule of rates to be brought into effect by the Company in its billings from and after a date prospectively prescribed by the Board.

The complication which gives rise to these proceedings occurred on August 20, 1975, when the Company filed with the Board an application (not to be confused with the application filed on August 20, 1974) for an order "approving changes in existing rates, tolls or charges for gas supplied and services rendered by Northwestern Utilities Limited to its customers"; together with an application on September 25, 1975, for an interim order "approving changes in existing rates, tolls or charges for gas supplied and services rendered by Northwestern Utilities Limited to its customers pending final determination of the matter". The application of 1975 recites the history of the 1974 application and states that the operating costs and gas costs of the Company "have increased substantially over the amounts included in the 1974 application and continue to increase". After reciting that the Board in response to the 1974 application had awarded the applicant "interim refundable rates", the 1975 application went on to state:

> The existing rates charged by the Applicant for natural gas do not produce revenues sufficient to provide for its present or prospective proper operating and depreciation expense and a fair return on the property used in the service to the public.

Therefore the Company went on to apply for an order determining the rate base, and a fair return thereon, and fixing and approving rates for natural gas supplied by the Company to its customers. The Company sought as well an order giving effect to "such part of any losses incurred by the applicant as may be due to any undue delay in the hearing and determining of the application", apparently paraphrasing s. 31 of The Gas Utilities Act. The 1975 application seeks as well interim rates "pending the fixing of final rates".

It is also relevant to note in passing that the 1974 application indeed had its own roots in a prior procedure before the Board initiated by the Board itself under s. 27 of The Gas Utilities Act in 1974. In June 1974, the Company applied for an interim rate increase. and after a hearing in July 1974 the application was denied on August 19, 1974, and the application of August 20, 1974, was thereupon filed.

By its order of October 1, 1975, the Board granted an interim increase in rates the effect of which was to allow the Company to receive $2,785,000 in excess of its revenues for 1975 which would have been received under the then existing rates. The question immediately arises as to whether this sum represents increased expenses to be incurred by the Company for the period after the interim rates became effective (October 1, 1975) or whether it represents expenses incurred and unrecovered in the past. It was from this interim order that the City of Edmonton (herein referred to as 'the City') appealed to the Appellate Division of the Supreme Court of Alberta pursuant to s. 62 of The Public Utilities Board Act:

> (1) Subject to subsection (2) [the requirement of leave], upon a question of jurisdiction or upon a

> question of law, an appeal lies from the Board to the Appellate Division of the Supreme Court of Alberta.

The Appellate Division of the Supreme Court of Alberta set aside the Board order of October 1, 1975, and referred the matter to the Board "for further consideration and redetermination". One preliminary argument can be disposed of at the outset. It was argued in the Courts below, as well as in this Court, that the interim order under appeal (dated October 1, 1975) was made pursuant to the 1974 rate application, either as a variance of the 1974 order pursuant to s. 56 of The Public Utilities Board Act, or as an interim order in respect of the 1974 application. That submission, whatever its effect, was rejected by the Court of Appeal and must be rejected here. On the face of the interim order is found a reference to "the application of N.U.L. dated the 20th day of August, 1975". That reference, when read with the transcript of the evidence at the hearing leaves no doubt that the interim order was made with respect to the 1975 application which clearly was an independent application to establish, pursuant to the aforementioned sections of The Gas Utilities Act, the statutory prerequisites to a new tariff of rates, and then a new tariff of rates.

I turn then to the first issue as to whether the Board by its interim order of October 1, 1975, has offended the provisions of s. 31 of The Gas Utilities Act by granting as alleged by the City an order permitting the recovery of losses incurred before the date of the application, August 20, 1975. It was not argued before this Court that the Board could not through s. 31 reach back to August 20, 1975, and grant a rate increase to recover costs thereafter incurred. The recitals to the order of October 1975 make it difficult to determine whether in fact the Board has invoked s. 31 in the interim rates established by the order or whether the Board has simply made an interim order under s. 51(2) of The Public Utilities Board Act. We need not determine the answer to that question in order to deal with this issue.

The issue is at this stage very narrow. No contest is raised as to the validity of the September 15, 1975, order nor the various interim rates authorized in the 1974 application. The issue is simply whether or not the Company by not applying in the 1974 application for a further interim order has caused the Board to respond to the new application in 1975 in such a way as to authorize a new tariff which when implemented by the Company will have the effect of recovering from future gas consumers revenue losses incurred by the Company with respect to gas deliveries made to consumers prior to the date of the application in question (August 20, 1975) or prior to the advent of the October 1, 1975, rates but in a manner not authorized by s. 31.

The Appellate Division of the Supreme Court of Alberta in both the judgments of Clement J.A. and McDermid J.A., as well as counsel before this Court, devoted a considerable amount of attention to the accounting evidence filed by the Company with reference to the total revenue requirement of the Company in the years 1974 and 1975 and to the possibility that the inclusion in the rate base or the operating expenses established in Phase I of the 1975 application of the additional expenses which gave rise to the 1975 application, will have the effect of violating or going beyond s. 31 by authorizing rates which will have the effect of recovering past losses. We are here not concerned with capitalized losses because there is no suggestion that the rate base will be enlarged by the inclusion of any historical loss in the sense of an accounting deficit in prior fiscal intervals but rather with revenue losses other than those which may be recovered pursuant to s. 31 and which relate to the period from and after August 20, 1975. These losses of course have no relationship to a rate base computed and established pursuant to s. 28 of The Gas Utilities Act. We are concerned only with whether or not the Board in its processes has determined the total operating expenses for some period, as well as the fair return on the rate base, so as to enable the Board to calculate prospectively the anticipated total revenue requirement of the utility and thereby establish rates which prospectively will produce future revenues to match the estimated future total revenue requirement.

This procedure was the subject of comment by Porter J.A. in Re Northwestern Utilities Ltd. [(1960), 25 D.L.R. (2d) 262.] at p. 290, and which comments I find apt in the circumstances now before us:

> One effect of this ruling is that future consumers will have to pay for their gas a sum of money which equals that which consumers prior to August 31, 1959 ought to have paid but did not pay for gas they had used. In short, the undercharge to one group of consumers for gas used in the

> past is to become an overcharge to another group on gas it uses in the future. When the Board capitalized this sum, it made all the future consumers debtors to the company for the total amount of the deficiency, payable ratably with interest from their respective future gas consumption.

It is conceded of course that the Act does not prevent the Board from taking into account past experience in order to forecast more accurately future revenues and expenses of a utility. It is quite a different thing to design a future rate to recover for the utility a 'loss' incurred or a revenue deficiency suffered in a period preceding the date of a current application. A crystallized or capitalized loss is, in any case, to be excluded from inclusion in the rate base and therefore may not be reflected in rates to be established for future periods.

The evidence submitted by the Company on the hearing of the 1975 application centred largely upon the urgent need for interim refundable rates by which the Company;

> can recover its costs of service and earn an adequate return on its utility assets for the year 1975. If the interim rates requested are nor granted, the costs of providing natural gas service would not be fully recovered.

The evidence goes on to outline the utility income under existing rates for the years 1975 and 1976 and it is stated that these rates unless augmented by interim rates as proposed will produce a shortfall in revenue of approximately $700,000 per month. The accounts so filed reveal computations which show the need for an additional $2.785 million for the year 1975 of which operating expenses represent $2.105 million. Unhappily, the record does not reveal whether all the components of the additional $2.785 million are recurring expenses and costs, or legitimate demands for return on capital, which will run evenly into the future. It may be that in the quarterly period of 1975 remaining at the time of the order, these projections will exceed or be less than the actual expenses to be incurred in that very quarterly period. On this the evidence is strangely silent. The evidence of the treasurer of the Company deals with the revenues for the year 1975 as follows:

> A. The revenues from gas sales for the test year 1975 of $87,265,000 as shown on line 6 of Statement 2.01 (Forecast--Proposed Rates) constitutes $84,480,000 of revenues forecast under existing rates as shown on Line 6 of Statement 2.01 (Forecast--Existing Rates) and $2,785,000 of additional revenues to earn a utility rate of return of 9.93 per cent. The increase is that estimated to be derived from introduction on October 1, 1975, of the requested interim rates, including an increase in franchise tax of $120,000.
>
> Q. On what year are the interim rates designed?
>
> A. 1975 was chosen as the test year and rates were designed to recover 1975 costs.

In its application for interim rates the Company reduces the effect of the anticipated loss of revenue to the conclusion:

> The rate of return on the base rate drops from 9 percent in 1974 to 8.43 percent in 1975 and further declines to 6.77 percent in 1976. The requested rate of return on rate base for 1975 under the proposed rates is 9.93 percent. This difference of 1 1/2 percent represents $1,600,000 in utility income.

This reference would appear to be to the difference between the prevailing rates in 1975 prior to October 1st and the rates which would prevail in 1975 under the proposal made for the rates effective October 1, 1975. The application for the interim rates goes on to state:

> Without rate relief in the form of interim rates for the balance of 1975, the imputed return on common equity drops to 10.2 percent compared to the recommended equity return of 14 5/8 percent to 15 1/8 percent ...

From this and like excerpts from evidence, testamentary and documentary, the City has taken the view that the augmentation to rates for the last quarter of 1975 sought by the Company and granted by the Board has in effect been a recognition of a deemed increase in the rate base or operating expenses by the inclusion therein of an otherwise unrecoverable loss in that part of the year 1975 preceding the 1975 application filed on August 20. Additionally, or perhaps more accurately, alternatively, the City has put the argument that the Company by its interim rate proposal has sought to recover in 1975 additional costs of $2.785 million without in any way establishing that the revenue so sought is required to match expenses to be incurred either during the effective period of the new interim rates, or is to recover lost revenue in the manner authorized by s. 31. In support of this argument, the City points out that the sum of $2.1 million, which is said to be required to meet increases in operating expenses, is not isolated and shown to be additional expenses to be incurred in the last quarter of 1975 but rather is the excess of 1975 expenses over and above those forecast in the earlier proceedings and which excess is forecast on the basis of actual expenditures in the first 6 months of 1975 together with anticipated expenditures in the last 6 months of 1975.

The Company meets this argument by the submission that losses contemplated by s. 31 cannot be discerned until the close of the fiscal period selected as the basis for the application for new rates and that this is peculiarly so in the case of a gas utility by reason of fluctuating conditions beyond the control of the utility. The Board in disposing of these opposing positions states simply:

> AND THE BOARD having considered the argument of counsel for Interveners that the application for interim refundable rates by N.U.L. should be rejected, in whole or in part, on the grounds that the increased interim refundable rates are for the purpose of recovering "past losses" which they claim have been incurred by N.U.L. since January 1, 1975:
>
> AND THE BOARD considering that the forecast revenue deficiency in the 1975 future test year requested by N.U.L. cannot be properly characterized as "past losses".

The terminology "past losses", employed perhaps by all parties before the Board and adopted by the Board in its order, makes it difficult in reviewing the record as well as the various orders of the Board to determine whether or not the Board was indeed attempting to isolate the elements to be taken into account by the Board in discharging its functions under ss. 27, 28 and 29 of The Gas Utilities Act with reference to specific parts of the calendar year 1975. If, for example, the Board had assumed that the additional revenue sought in the application of September 25, 1975, for an interim order pending the determination of the application of August 20, 1975, was to match expenses forecast to be incurred by the Company in the last quarter of 1975, then there would be no attempt by the Board to take into account revenue losses incurred prior to August 20, 1975, and thus no failure on the part of the Board to comply with the statute and with s. 31 in particular. The process of matching forecast revenues to be realized from the proposed interim rates against the forecast expenses comprising the total revenue requirements for the last quarterly period would be complete. It is impossible to discern whether or not that is the result which is sought to be reflected by the Board in its order of October 1, 1975. Such may well be the case, but on the other hand, it might be as submitted by the City that these additional expenses totalling $2.785 million are in whole or in part the result of annualizing expenses incurred before and/or after August 20, 1975, so that the total revenue requirement for the "test year" need be augmented by $2.785 million in order to meet the total revenue requirements for the year. It is in my view wholly unnecessary to enter the debate as to whether or not in making the estimates for future expenses a fiscal period of a year, two years, a half year, etc., need be selected. What is required by the statute is an estimate by the Board of the future needs of the utility which are recognized in the statute to be compensable by the operation in the future of the rates prescribed by the Board. Similarly the forecast of revenues to be recovered by the proposed rates need not be predicated necessarily upon a hypothetical or real fiscal year or a shorter period. Obviously in a seasonal enterprise such as the gas utility business a full calendar fiscal period represents the marketing picture throughout the four seasons of the year. Equally obviously, recurring cash outlays relevant to expenses unevenly incurred throughout the year can be annualized either by an accounting adjustment where the expense incurred relates to a longer period or extends beyond the fiscal year in question, or can be annualized where the expense incurred relates to a segment of the fiscal period. In any case the administrative mechanics to be adopted in the discharge of the function mandated by The Gas Utilities Act are exclusively within the power of the Board. We need not here deal with the question of arbitrariness in the discharge of administrative functions for there is no evidence on the record before this Court raising any such issue. This Court is concerned only with the issue as to whether the Board in the performance of its duties under the statUte has exceeded the power and authority given to it by the Legislature. Clement J.A. has observed in his reasons:

> [P]rima facie the new tentative rate base includes an amount for revenue losses in 1975 up to the date of the application in August, since the figures do not purport to apportion the loss between the two periods of the year.

I am not prepared to say that a prima facie case has been established that the effect of the application of the interim rates from October 1, 1975, onwards will be the recovery in the future of revenue shortfalls incurred prior to August 20, 1975. Indeed, in my respectful view, the test is not whether the "new tentative rate base includes an amount for revenue losses" but rather the question is whether or not the interim rates prospectively applied will produce an amount in excess of the estimated total revenue requirements for the same period of the utility by reason of the inclusion in the computation of those future requirements of revenue shortfalls which have occurred prior to the date of the application in question, whether or not those "shortfalls" have been somehow incorporated into the rate base or have been included in the operating expenses forecast for the period in which the new interim rates will be applied, subject always to the Board's limited power under s. 31.

The Company submitted to this Court that a determination of what is or is not a 'past loss' is a pure question of fact and as such is not subject to appeal by reason of s. 62 of The Public Utilities Board Act, supra, which limits appeals from Board decisions to questions of "law or jurisdiction". The appeal before this Court involves a determination of the intent of the Legislature with respect to the Board's jurisdiction to take into account shortfalls in revenue or excess expenditures occurring or properly allocable to a period of time prior to an application for the establishment of rates under the Act. The Board's decision as to the characterization of "the forecast revenue deficiency in the 1975 future test year" of the Company involves a determination of the matters of which cognizance may be taken by the Board in setting rates under the statute. This is a question of law and may properly be made the subject of an appeal to a court pursuant to s. 62. The disposition of an application which, as I have said, involved the Board in construing ss. 28 and 31 of The Gas Utilities Act, raises a question of law and may well go to the jurisdiction of the Board.

However, it is not possible for the reviewing tribunal in the circumstances in this proceeding to ascertain from the Board order whether the Board acted within or outside the ambit of its statutory authority. The form and content of the Board's order are so narrow in scope and of such extraordinary brevity that one is left without guidance as to the basis upon which the rates have been established for the period October 1, 1975, onwards. Hence this further submission of the Company must fail.

I turn now to the second issue, namely the application of s. 8 of The Administrative Procedures Act of Alberta, supra, to these proceedings. This provision imposes upon certain administrative tribunals the obligation of providing the parties to its proceedings with a written statement of its decision and the facts upon which the decision is based and the reasons for it. Section 8 states:

> Where an authority exercises a statutory power so as to adversely affect the rights of a party, the authority shall furnish to each party a written statement of its decision setting out
>
> (a) the findings of fact upon which it based its decision, and
> (b) the reasons for the decision.

The "reasons" handed down by the Board consist of the following:

INTERIM ORDER

> UPON THE APPLICATION of Northwestern Utilities Limited, (hereinafter referred to as "N.U.L.") to the Public Utilities Board for an Order or Orders approving changes in existing rates, tolls or charges for gas supplied and services rendered by N.U.L. to its customers;
>
> AND UPON READING the application of N.U.L. dated the 20th day of August, 1975 and the Affidavit of Dorothea E. Blackwood concerning service by mail and by newspaper publication of a Notice of the matter as directed by the Board and written evidence of witnesses of N.U.L. and other material filed in support of the application;
>
> AND UPON HEARING an application made by N.U.L. on September 25, 1975, for an Interim Order approving changes in existing rates, tolls or charges for gas supplied and services rendered by N.U.L. to its customers pending final determination of the matter;
>
> AND UPON HEARING the application, testimony and submission of witnesses and counsel for N.U.L.;
>
> AND THE BOARD having considered the argument of counsel for Interveners that the application for interim refundable rates by N.U.L. should be rejected, in whole or in part, on the grounds that the increased interim refundable rates are for the purpose of recovering "past losses" which they claim have been incurred by N.U.L. since January 1, 1975;
>
> AND THE BOARD considering that the forecast revenue deficiency in the 1975 future test year requested by N.U.L. cannot be properly characterized as "past losses".
>
> AND THE BOARD considering that delay in granting an interim increase in rates may adversely affect N.U.L.'s financial integrity and customer service;
>
> AND N.U.L. having undertaken to refund to its customers such amounts as the Board may direct if any of the said interim rates are changed after further hearing.
>
> IT IS ORDERED as follows: ...

The law reports are replete with cases affirming the desirability if not the legal obligation at common law of giving reasons for decisions (vide Gill Lumber Chipman (1973) Ltd. v. United Brotherhood of Carpenters and Joiners of America Local 2142 [(1973), 7 N.B.R. (2d) 41 (N.B.S.C.A.D.).], per Hughes C.J.N.B. at p. 47; MacDonald v. The Queen [(1976), 29 C.C.C. (2d) 257.], per Laskin C.J.C. at p. 262). This obligation is a salutary one. It reduces to a considerable degree the chances of arbitrary or capricious decisions, reinforces public confidence in the judgment and fairness of administrative tribunals, and affords parties to administrative proceedings an opportunity to assess the question of appeal and if taken, the opportunity in the reviewing or appellate tribunal of a full hearing which may well be denied where the basis of the decision has not been disclosed. This is not to say, however, that absent a requirement by statute or regulation a disposition by an administrative tribunal would be reviewable solely by reason of a failure to disclose its reasons for such disposition.

The Board in its decision allowing the interim rate increase which is challenged by the City failed to meet the requirements of s. 8 of The Administrative Procedures Act. It is not enough to assert, or more accurately, to recite, the fact that evidence and arguments led by the parties have been considered. That much is expected in any event. If those recitals are eliminated from the 'reasons' of the Board all that is left is the conclusion of the Board "that the forecast revenue deficiency in the 1975 future test year requested by the Company cannot be properly characterized as "past losses"". The failure of the Board to perform its function under s. 8 included most seriously a failure to set out "the findings of fact upon which it based its decision" so that the parties and a reviewing tribunal are unable to determine whether or not, in discharging its functions, the Board has remained within or has transgressed the boundaries of its jurisdiction established by its parent statute. The obligation imposed under s. 8 of the Act is not met by the bald assertion that, as Keith J. succinctly put it in Re Canada Metal Co. Ltd. et al. and MacFarlane [(1973), 1 O.R. (2d) 577.], at p. 587, when dealing with a similar statutory requirement, "my reasons are that I think so".

The appellants are not assisted by the decision of the

Appellate Division of the Supreme Court of Alberta in Dome Petroleum Ltd. v. Public Utilities Board (Alberta) and Canadian Superior Oil Ltd. [(1976), 2 A.R. 453.], affirmed by this Court at [1977] 2 S.C.R. 822 to the effect that under s. 8 of The Administrative Procedures Act the reasons must be proper, adequate and intelligible, and must enable the person concerned to assess whether he has grounds of appeal. Nor can the Board rely on the peculiar nature of the order in this case, being an interim order with the amounts payable thereunder perhaps being refundable at some later date, to deny the obligation to give reasons. Brevity in this era of prolixity is commendable and might well be rewarded by a different result herein but for the fact that the order of the Board reveals only conclusions without any hint of the reasoning process which led thereto. For example, none of the factors which the Board took into account, in reaching its conclusion that the amounts contested were not "past losses" are revealed so that a reviewing tribunal cannot with any assurance determine that the statutory mandates bearing upon the Board's process have been heeded.

The Appellate Division of the Supreme Court of Alberta, after coming to the same result, vacated the Board's order and referred the matter to the Board for further consideration and determination pursuant to s. 64 of The Public Utilities Board Act. In doing so, it is evident from the reasons for judgment of the said Court that the Court properly viewed its appellate jurisdiction under s. 64 of The Public Utilities Board Act as a limited one. It is not for a court to usurp the statutory responsibilities entrusted to the Board, except in so far as judicial review is expressly allowed under the Act. It is, of course, otherwise where the administrative tribunal oversteps its statutory authority or fails to perform its functions as directed by the statute. Questions as to how and when operating expenses are to be measured and recovered through prescribed rates are, subject to the limits imposed by the Act itself, for the Board to decide, and the procedures for such decisions if made within the confines of the statute are administrative matters which are better left to the Board to determine (vide City of Edmonton v. Northwestern Utilities Limited, supra, per Locke J. at p. 406).

As for the participation of The Public Utilities Board in these proceedings, it was pointed out to the Court that s. 65 of The Public Utilities Board Act entitles the Board "to be heard ... upon the argument of any appeal". Under s. 66 of the Act the Board is shielded from any liability in respect of costs by reason or in respect of an appeal.

Section 65 no doubt confers upon the Board the right to participate on appeals from its decisions, but in the absence of a clear expression of intention on the part of the Legislature, this right is a limited one. The Board is given locus standi as a participant in the nature of an amicus curiae but not as a party. That this is so is made evident by s. 63(2) of The Public Utilities Board Act which reads as follows:

> The party appealing shall, within ten days after the appeal has been set down, give to the parties affected by the appeal or the respective solicitors by whom the parties were represented before the Board, and to the secretary of the Board, notice in writing that the case has been set down to be heard in appeal, and the appeal shall be heard by the court of appeal as speedily as practicable.

Under s. 63(2) a distinction is drawn between "parties" who seek to appeal a decision of the Board or were represented before the Board, and the Board itself. The Board has a limited status before the Court, and may not be considered as a party, in the full sense of that term, to an appeal from its own decisions. In my view, this limitation is entirely proper. This limitation was no doubt consciously imposed by the Legislature in order to avoid placing an unfair burden on an appellant who, in the nature of things, must on another day and in another cause again submit itself to the rate fixing activities of the Board. It also recognizes the universal human frailties which are revealed when persons or organizations are placed in such adversarial positions.

This appeal involves an adjudication of the Board's decision on two grounds both of which involve the legality of administrative action. One of the two appellants is the Board itself, which through counsel presented detailed and elaborate arguments in support of its decision in favour of the Company. Such active and even aggressive participation can have no other effect than to discredit the impartiality of an administrative tribunal either in the case where the matter is referred back to it, or in future proceedings involving similar interests and issues or the same parties. The Board is given a clear opportunity to make its point in its reasons for its decision, and it abuses one's notion of propriety to countenance its participation as a full-fledged litigant in this Court, in complete adversarial confrontation with one of the principals in the contest before the Board itself in the first instance.

It has been the policy in this Court to limit the role of an administrative tribunal whose decision is at issue before the Court, even where the right to appear is given by statute, to an explanatory role with reference to the record before the Board and to the making of representations relating to jurisdiction. (Vide The Labour Relations Board of the Province of New Brunswick v. Eastern Bakeries Limited et al. [[1961] S.C.R. 72.]; The Labour Relations Board of Saskatchewan v. Dominion Fire Brick and Clay Products Limited et al. [[1947] S.C.R. 336.]) Where the right to appear and present arguments is granted, an administrative tribunal would be well advised to adhere to the principles enunciated by Aylesworth J.A. in International Association of Machinists v. Genaire Ltd. and Ontario Labour Relations Board [(1958), 18 D.L.R. (2d) 588.], at pp. 589, 590:

> Clearly upon an appeal from the Board, counsel may appear on behalf of the Board and may present argument to the appellate tribunal. We think in all propriety, however, such argument should be addressed not to the merits of the case as between the parties appearing before the Board, but rather to the jurisdiction or lack of jurisdiction of the Board. If argument by counsel for the Board is directed to such matters as we have indicated, the impartiality of the Board will be the better emphasized and its dignity and authority the better preserved, while at the same time the appellate tribunal will have the advantage of any submissions as to jurisdiction which counsel for the Board may see fit to advance.

Where the parent or authorizing statute is silent as to the role or status of the tribunal in appeal or review proceedings, this Court has confined the tribunal strictly to the issue of its jurisdiction to make the order in question. (Vide Central Broadcasting Company Ltd. v. Canada Labour Relations Board and International Brotherhood of Electrical Workers, Local Union No. 529 [[1977] 2 S.C.R. 112.].)

In the sense the term has been employed by me here, "jurisdiction" does not include the transgression of the authority of a tribunal by its failure to adhere to the rules of natural justice. In such an issue, when it is joined by a party to proceedings before that tribunal in a review process, it is the tribunal which finds itself under examination. To allow an administrative board the opportunity to justify its action and indeed to vindicate itself would produce a spectacle not ordinarily contemplated in our judicial traditions. In Canada Labour Relations Board v. Transair Ltd. et al. [[1977] 1 S.C.R. 722.], Spence J. speaking on this point, stated at pp. 746-7:

> It is true that the finding that an administrative tribunal has not acted in accord with the principles of natural justice has been used frequently to determine that the Board has declined to exercise its jurisdiction and therefore has had no jurisdiction to make the decision which it has purported to make. I am of the opinion, however, that this is a mere matter of technique in determining the jurisdiction of the Court to exercise the remedy of certiorari and is not a matter of the tribunal's defence of its jurisdiction. The issue of whether or not a board has acted in accordance with the

> principles of natural justice is surely not a matter upon which the Board, whose exercise of its functions is under attack, should debate, in appeal, as a protagonist and that issue should be fought out before the appellate or reviewing Court by the parties and not by the tribunal whose actions are under review.

There are other issues subordinate to the two principal submissions which I have discussed above but which are inappropriate for comment at this stage by reason of the disposition which I propose in respect to this appeal. I would dismiss the appeal with costs to the respondent The City of Edmonton as against the appellant Northwestern Utilities Limited. In the result, therefore, the matter would revert to the Board for a continuation of the processing of the application by the Company of August 20, 1975, involving, as discussed above, the ascertainment by any means appropriate to the provisions of the statute, the expenses estimated to be incurred in the future and to be therefore properly recoverable by the application of the rates to be established by the Board; and in the event that s. 31 be invoked for the ascertainment of only those expenses which had been incurred after the application of August 20, 1975. Any further analysis of the factual background and subordinate issues would, in view of this disposition, be inappropriate.

Appeal dismissed with costs.

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Ontario Energy Board | **Commission de l'énergie de l'Ontario**

Ontario

EB-2013-0170

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, (Schedule B);

AND IN THE MATTER OF an application by Sioux Lookout Hydro Inc. for an order approving just and reasonable rates and other charges for electricity distribution to be effective May 1, 2014.

BEFORE: Marika Hare
Presiding Member

Allison Duff
Member

DECISION and ORDER

March 13, 2014

Sioux Lookout Hydro Inc. ("Sioux Lookout") filed an application with the Ontario Energy Board (the "Board") on October 21, 2013 under section 78 of the Act, seeking approval for changes to the rates that Sioux Lookout charges for electricity distribution, effective May 1, 2014 (the "Application").

The Application met the Board's requirements as detailed in the *Report of the Board: Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach* (the "RRFE Report") dated October 18, 2012 and the *Filing Requirements for Electricity Distribution Rate Applications* (the "Filing Requirements") dated July 17, 2013. Sioux Lookout selected the Price Cap Incentive Rate-Setting ("Price Cap IR") option to adjust its 2014 rates. The Price Cap IR/Annual IR Index methodology provides for a mechanistic and formulaic adjustment to distribution rates and charges in the period between cost of service applications. Sioux Lookout last appeared before the Board with a full cost of service application for the 2013 rate year in the EB-2012-0165 proceeding. In this proceeding, Sioux Lookout also seeks approval for adjustments to revenue-to-cost ratios.

The Board conducted a written hearing and Board staff participated in the proceeding. No letters of comment were received.

While the Board has considered the entire record in this proceeding, it has made reference only to such evidence as is necessary to provide context to its findings. The following issues are addressed in this Decision and Order:

- Price Cap Index Adjustment;
- Rural or Remote Electricity Rate Protection Charge;
- Revenue-to-Cost Ratio Adjustments;
- Retail Transmission Service Rates; and
- Review and Disposition of Group 1 Deferral and Variance Account Balances.

Price Cap Index Adjustment

The Board issued the *Report on Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors* (the "Price Cap IR Report") which provides the 2014 rate adjustment parameters for distribution companies selecting either the Price Cap IR or Annual IR Index option.

Distribution rates under the Price Cap IR option are adjusted by an inflation factor, less a productivity factor and a stretch factor. The inflation factor for 2014 rates is 1.7%. Based on the total cost benchmarking model developed by Pacific Economics Group Research, LLC, the Board determined that the appropriate value for the productivity factor is zero percent. The Board also determined that the stretch factor can range from 0.0% to 0.6% for distributors selecting the Price Cap IR option, assigned based on a distributor's cost evaluation ranking. In the Price Cap IR Report, the Board assigned Sioux Lookout a stretch factor of 0.3%.

As a result, the net price cap index adjustment for Sioux Lookout is 1.4 % (i.e. 1.7% - (0% + 0.3 %)). The price cap index adjustment applies to distribution rates (fixed and variable charges) uniformly across all customer classes. The price cap index adjustment does not apply to the components of delivery rates set out in the list below.

- Rate Riders;
- Rate Adders;
- Low Voltage Service Charges;
- Retail Transmission Service Rates;

- Wholesale Market Service Rate;
- Rural or Remote Electricity Rate Protection Charge;
- Standard Supply Service – Administrative Charge;
- Transformation and Primary Metering Allowances;
- Loss Factors;
- Specific Service Charges;
- MicroFit Charge; and
- Retail Service Charges.

Rural or Remote Electricity Rate Protection Charge

The Board issued a Decision and Rate Order (EB-2013-0396) establishing the Rural or Remote Electricity Rate Protection ("RRRP") benefit and charge for 2014. The Board determined that the RRRP charge to be paid by all rate regulated distributors and collected by the Independent Electricity System Operator ("IESO") shall be increased to $0.0013 per kWh effective May 1, 2014, from the current $0.0012 per kWh. The draft Tariff of Rates and Charges flowing from this Decision and Order reflects the new RRRP charge.

Revenue-to-Cost Ratio Adjustments

Revenue-to-cost ratios measure the relationship between the revenues expected from a class of customers and the level of costs allocated to that class. The Board has established target ratio ranges for electricity distributors in its report *Application of Cost Allocation for Electricity Distributors*, dated November 28, 2007 and in its updated report *Review of Electricity Distribution Cost Allocation Policy,* dated March 31, 2011.

In its 2013 cost of service application (EB-2012-0165), the Board approved Sioux Lookout's proposed revenue-to-cost ratios[1]. Changes in 2014 include a move to an 83.08% revenue-to-cost ratio for the Street Lighting rate class and a reduction in the revenue-to-cost ratio for the General Service 50 to 4,999 kW rate class from 119.23% to 115.80%.
The table below outlines the proposed revenue-to-cost ratios.

[1] Decision & Order dated August 22, 2013, page 16

Current and Proposed Revenue-to-Cost Ratio

Rate Class	Current 2013 Ratio	Proposed 2014 Ratio
Residential	96.35	96.35
General Service Less Than 50 kW	109.85	109.85
General Service 50 to 4,999 kW	119.23	115.80
Street Lighting	76.54	83.08
Unmetered Scattered Load	81.30	81.30

The Board agrees that the proposed revenue-to-cost ratios are consistent with the EB-2012-0165 decision and approves the revenue-to-cost ratios as filed.

Retail Transmission Service Rates

Electricity distributors are charged for transmission costs at the wholesale level and then pass on these charges to their distribution customers through the Retail Transmission Service Rates ("RTSRs"). Variance accounts are used to capture differences in the rate that a distributor pays for wholesale transmission service compared to the retail rate that the distributor is authorized to charge when billing its customers (i.e. variance Accounts 1584 and 1586).

The Board issued revision 3.0 of the *Guideline G-2008-0001 - Electricity Distribution Retail Transmission Service Rates* (the "RTSR Guideline") which outlines the information that the Board requires electricity distributors to file to adjust their RTSRs for 2014. The RTSR Guideline requires electricity distributors to adjust their RTSRs based on a comparison of historical transmission costs adjusted for the new Uniform Transmission Rates ("UTR") levels and the revenues generated under existing RTSRs. Similarly, embedded distributors, such as Sioux Lookout, must adjust their RTSRs to reflect any changes to the applicable Sub-Transmission RTSRs of their host distributor, which in this case is Hydro One Networks Inc.

The Board approved new rates for Hydro One's Sub-Transmission class, including the applicable RTSRs, effective January 1, 2014 (EB-2013-0141), as shown in the following table.

2014 Sub-Transmission RTSRs

Network Service Rate	$3.23 per kW
<u>Connection Service Rates</u> Line Connection Service Rate Transformation Connection Service Rate	 $0.65 per kW $1.62 per kW

The Board finds that these 2014 Sub-Transmission class RTSRs are to be incorporated into the filing module.

Review and Disposition of Group 1 Deferral and Variance Account Balances

The *Report of the Board on Electricity Distributors' Deferral and Variance Account Review Initiative* provides that, during the IRM plan term, the distributor's Group 1 account balances will be reviewed and disposed if the preset disposition threshold of $0.001 per kWh (debit or credit) is exceeded. The onus is on the distributor to justify why any account balance in excess of the threshold should not be disposed. As the total Group 1 balance of $55,628 resulted in a debit claim of $0.0008 per kWh, it did not exceed the preset disposition threshold. Sioux Lookout did not seek disposition of the Group 1 balances in its Application.

However, Sioux Lookout indicated that there was an input error in its 2012 IRM evidence (EB-2011- 0102) that affected its total Group 1 calculation in this Application. Sioux Lookout submitted that the credit balance in Account 1595 sub-account 2010 of ($141,174) was mislabeled in the evidence as a 2009 balance. It stated that the 2010 credit balance should not have been included in the Group 1 total balance requested and approved for disposition. The "true" 2009 balance was zero because there were no DVA rate riders approved by the Board in its 2009 Decision EB-2008-0210.

Group 1 Deferral and Variance Account Balances – 2012 IRM

Account Name	Account Number	Principal Balance A	Interest Balance B	Total Claim C = A + B
LV Variance Account	1550	$44,149	-$83	$44,066
RSVA - Wholesale Market Service Charge	1580	-$109,753	-$2,086	-$111,839
RSVA - Retail Transmission Network Charge	1584	-$13,347	-$272	-$13,619
RSVA - Retail Transmission Connection Charge	1586	-$50,583	-$1,121	-$51,704
RSVA - Power (excluding Global Adjustment)	1588	-$179,717	$432	-$179,285
RSVA – Power – Sub-Account – Global Adjustment	1588	-$60,781	-$2,425	-$63,206
Recovery of Regulatory Asset Balances	1590	$1	$13	$14
Disposition and Recovery of Regulatory Balances (2008)	1595	$347,330	$38,599	$385,929
Disposition and Recovery of Regulatory Balances (2009)	1595	-$205,130	$63,956	-$141,174
Total Group 1 Excluding Global Adjustment		**-$167,050**	**$99,438**	**-$67,612**
Total Group 1		**-$227,831**	**$97,013**	**-$130,818**

The following year, in Sioux Lookout's 2013 Cost of Service proceeding (EB-2012-0165), the credit balance in Account 1595 - 2010 of ($154,214) was included in the evidence, as it should have been included. As a result, the 2010 credit balance was mistakenly returned to customers a second time, as indicated in the following table.

Group 1 Deferral and Variance Account Balances – 2013 Cost of Service

Account Name	Account Number	Principal Balance A	Interest Balance B	Total Claim C = A + B
LV Variance Account	1550	$15,524	$1,773	$17,297
RSVA - Wholesale Market Service Charge	1580	-$82,620	-$2,226	-$84,846
RSVA - Retail Transmission Network Charge	1584	$1,331	$430	$1,761
RSVA - Retail Transmission Connection Charge	1586	-$15,737	-$292	-$16,029
RSVA - Power (excluding Global Adjustment)	1588	$40,127	$2,112	$42,239
RSVA – Power – Sub-Account – Global Adjustment	1588	-$69,209	-$36	-$69,245
Recovery of Regulatory Asset Balances	1590	0	0	0
Disposition and Recovery of Regulatory Balances (2008)	1595	-$44,366	-$3,336	-$47,702
Disposition and Recovery of Regulatory Balances (2009)	1595	0	0	0
Disposition and Recovery of Regulatory Balances (2010)	1595	-$213,808	$59,594	-$154,214
Total Group 1 Excluding Global Adjustment		**-$299,549**	**$58,055**	**-$241,494**
Total Group 1		**-$368,758**	**$58,019**	**-$310,739**

In this 2014 IRM Application, Sioux Lookout indicated that corrections to these past errors were included in the Group 1 total balance. A correcting debit balance of $149,135 for Account 1595-2010 was included in the Group 1 total as indicated in the following table.

Group 1 Deferral and Variance Account Balances – 2014 IRM

Account Name	Account Number	Principal Balance A	Interest Balance B	Total Claim C = A + B
LV Variance Account	1550	$45,813	$1,675	$47,488
RSVA - Wholesale Market Service Charge	1580	-$7,014	$306	-$6,708
RSVA - Retail Transmission Network Charge	1584	$1,585	$296	$1,881
RSVA - Retail Transmission Connection Charge	1586	$5,858	$91	$5,949
RSVA - Power	1588	$17,998	$993	$18,991
RSVA - Global Adjustment	1589	-$16,487	$2779	-$13,708
Recovery of Regulatory Asset Balances	1590	0	0	0
Disposition and Recovery of Regulatory Balances (2008)	1595	$243	$2,148	$2,391
Disposition and Recovery of Regulatory Balances (2009)	1595	0	0	0
Disposition and Recovery of Regulatory Balances (2010)	1595	$206,450	-$57,315	$149,135
Disposition and Recovery of Regulatory Balances (2011)	1595	-$138,243	-$11,547	-$149,790
Total Group 1 Excluding Global Adjustment – Account 1589		**$132,690**	**-$63,353**	**$69,337**
Total Group 1		**$116,203**	**-$60,574**	**$55,629**

Board staff submitted that Sioux Lookout was seeking to be compensated for past errors through this IRM application. Board staff submitted that Account 1595 – 2010 was disposed of on a final basis in the Board's 2013 decision in EB-2012-0165. The proposed inclusion of $149,135 in the Group 1 total balance raises the issue of retroactive ratemaking.

Board staff indicated that in past Board decisions, recovery of past costs or charges were not permitted if the account had been disposed of on a final basis. Board staff also noted that past Board decisions have found that a utility has control of its books and records and has the responsibility to ensure mistakes do not occur. Given that the principles of certainty and finality are a necessary component of effective rate regulation[2], Board staff submitted it would be inappropriate for Sioux Lookout to recover the debit balances of $149,135 in Account 1595 – 2010 from its customers in the future.

[2] EB-2013-0022, Decision and Order, Veridian Motion to Review, April 25, 2013, p. 10

Board staff noted that a review of Sioux Lookout's audited financial statements indicates that a denial of the recovery sought would fail to raise any concern of financial viability for Sioux Lookout. Board staff's review indicates that Sioux Lookout's net income increased from $93,107 in 2009 to $308,169 in 2011.

Sioux Lookout disagreed with Board staff and submitted that sole responsibility for the error should not be placed on the company. The issue arose as a result of insufficient clarity in the Board's model and continuity schedules.

Sioux Lookout disagreed that its request would constitute retroactive rate making as the continuity model allows Account 1595 to capture residual amounts. Sioux Lookout feels the amount in question does represent a residual balance. Sioux Lookout maintained that there would be a significant financial impact should the amount of $149,135 be expensed. Sioux Lookout noted that its net income for 2012 was $241K, and the 2013 regulated return was deemed to be $219K as per EB-2012-0165. Sioux Lookout reported that a reduction in its net income by the amount in question would place Sioux Lookout's regulatory return on equity outside of the deadband of +/- 3% that has been adopted as a threshold financial performance indicator at which a regulatory review may be initiated.

Board Findings

The Board will not allow the collection of amounts that were previously declared final, as this would constitute retroactive rate-making. When a deferral or variance account balance is approved for disposition on a final basis, only the disposition may result in a residual balance if there is an over/under collection, or refund of the approved balance.

The courts have made it very clear that retroactive rate-making, the adjustment to rates after a final rate order has been issued, is not allowed. Rather, the principles of certainty and finality are a necessary component of effective rate regulation. To allow Sioux Lookout to correct an error after a final rate order was issued would be contrary to the legal principles upon which the Board performs its legislated mandate.

The Board finds that the denial of the request to recover the 2010 DVA amount is unlikely to have a material impact on the utility's cash flow. The financial viability of Sioux Lookout does not appear to be at risk in a sustained way as a result of its own errors in this case. The Board also notes that under-earning with respect to regulatory return on equity may not necessarily indicate any risk exposure to Sioux Lookout's financial viability. Finally, while the Board has set a deadband for regulatory earnings outside of the regulated rate of return, the instrument is a tool that triggers a regulatory review – not a guaranteed earnings floor for the utility.

The Board directs Sioux Lookout to exclude the Account 1595 - 2010 balance of $149,135 from its Group 1 table. As a result of this exclusion, the total Group 1 balance, including interest projected to April 30, 3014, will be a credit to customers of $93,507. This amount results in a total credit claim of $0.0013 which exceeds the preset disposition threshold. The Board directs Sioux Lookout to calculate the associated rate riders for inclusion in the draft rate order as outlined below.

IMPLEMENTATION

The Board has made findings in this Decision and Order which change the 2014 distribution rates from those proposed by Sioux Lookout.

The Board expects Sioux Lookout to file a draft Rate Order, including a proposed Tariff of Rates and Charges and all relevant calculations showing the impact of this Decision and Order on Sioux Lookout's determination of the final rates. Supporting documentation shall include, but not be limited to, filing a completed version of the 2014 IRM Rate Generator model and calculation of the rate riders, Tax Sharing model, Revenue to Cost ratio model and RTSR model.

A Rate Order will be issued after the steps set out below are completed.

THE BOARD ORDERS THAT:

1. Sioux Lookout shall file with the Board, a draft Rate Order that includes revised models in Microsoft Excel format and a proposed Tariff of Rates and Charges reflecting the Board's findings in this Decision by 7 days from date of issuance of Decision and Order.

2. Board staff shall file any comments on the draft Rate Order including the revised models and proposed rates with the Board and forward to Sioux Lookout within 7 days of the date of filing of the draft Rate Order.

3. Sioux Lookout shall file with the Board responses to any comments on its draft Rate Order including the revised models and proposed rates within 4 days of the date of receipt of comments.

All filings to the Board must quote file number **EB-2013-0170,** be made through the Board's web portal at https://www.pes.ontarioenergyboard.ca/eservice/ and consist of two paper copies and one electronic copy in searchable / unrestricted PDF format. Filings must clearly state the sender's name, postal address and telephone number, fax number and e-mail address. Parties must use the document naming conventions and document submission standards outlined in the RESS Document Guideline found at www.ontarioenergyboard.ca. If the web portal is not available parties may email their document to BoardSec@ontarioenergyboard.ca. Those who do not have internet access are required to submit all filings on a CD in PDF format, along with two paper copies. Those who do not have computer access are required to file 2 paper copies.

DATED at Toronto, March 13, 2014

ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

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Ontario Energy Board | Commission de l'énergie de l'Ontario

EB-2013-0119

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, (Schedule B);

AND IN THE MATTER OF an application by Chapleau Public Utilities Corporation for an order approving just and reasonable rates and other charges for electricity distribution to be effective May 1, 2014.

BEFORE: Marika Hare
Presiding Member

Allison Duff
Member

DECISION and RATE ORDER

March 13, 2014

Chapleau Public Utilities Corporation ("Chapleau PUC") filed an application with the Ontario Energy Board (the "Board") on September 10, 2013 under section 78 of the Act, seeking approval for changes to the rates that Chapleau PUC charges for electricity distribution, effective May 1, 2014 (the "Application").

The Application met the Board's requirements as detailed in the *Report of the Board: Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach* (the "RRFE Report") dated October 18, 2012 and the *Filing Requirements for Electricity Distribution Rate Applications* dated July 17, 2013. Chapleau PUC selected the Price Cap Incentive Rate-Setting ("Price Cap IR") option to adjust its 2014 rates. The Price Cap IR methodology provides for a mechanistic and formulaic adjustment to distribution rates and charges in the period between cost of service applications. Chapleau PUC last appeared before the Board with a full cost of service application for the 2012 rate year in the EB-2011-0322 proceeding. In this proceeding, Chapleau PUC also seeks approval for its request to recover amounts related to a billing error from Hydro One Networks Inc. ("Hydro One") for Low Voltage Service and adjustments to its Low Voltage Service rates.

The Board conducted a written hearing and Board staff participated in the proceeding. The Vulnerable Energy Consumers Coalition ("VECC") applied for and was granted intervenor status and cost eligibility with respect to the proposals regarding Low Voltage Service. No letters of comment were received.

While the Board has considered the entire record in this proceeding, it has made reference only to such evidence as is necessary to provide context to its findings. The following issues are addressed in this Decision and Rate Order:

- Price Cap Index Adjustment;
- Rural or Remote Electricity Rate Protection Charge;
- Revenue-to-Cost Ratio Adjustments;
- Retail Transmission Service Rates;
- Review and Disposition of Group 1 Deferral and Variance Account Balances;
- Hydro One Billing Error for Low Voltage Service; and
- Proposed Adjustments to Low Voltage Service Rates.

Price Cap Index Adjustment

The Board issued the *Report on Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors* (the "Price Cap IR Report") which provides the 2014 rate adjustment parameters for distribution companies selecting either the Price Cap IR or Annual IR Index option.

Distribution rates under the Price Cap IR option are adjusted by an inflation factor, less a productivity factor and a stretch factor. The inflation factor for 2014 rates is 1.7%. Based on the total cost benchmarking model developed by Pacific Economics Group Research, LLC, the Board determined that the appropriate value for the productivity factor is zero percent. The Board also determined that the stretch factor can range from 0.0% to 0.6% for distributors selecting the Price Cap IR option, assigned based on a distributor's cost evaluation ranking. In the Price Cap IR Report, the Board assigned Chapleau PUC a stretch factor of 0.45%.

As a result, the net price cap index adjustment for Chapleau PUC is 1.25% (i.e. 1.7% - (0% + 0.45%)). The price cap index adjustment applies to distribution rates (fixed and variable charges) uniformly across all customer classes. The price cap index adjustment does not apply to the components of delivery rates set out in the list below.

- Rate Riders;
- Rate Adders;
- Low Voltage Service Charges;
- Retail Transmission Service Rates;
- Wholesale Market Service Rate;
- Rural or Remote Electricity Rate Protection Charge;
- Standard Supply Service – Administrative Charge;
- Transformation and Primary Metering Allowances;
- Loss Factors;
- Specific Service Charges;
- MicroFit Charge; and
- Retail Service Charges.

Rural or Remote Electricity Rate Protection Charge

The Board issued a Decision and Rate Order (EB-2013-0396) establishing the Rural or Remote Electricity Rate Protection (“RRRP”) benefit and charge for 2014. The Board determined that the RRRP charge to be paid by all rate-regulated distributors and collected by the Independent Electricity System Operator shall be increased to $0.0013 per kWh effective May 1, 2014, from the current $0.0012 per kWh. The draft Tariff of Rates and Charges flowing from this Decision and Rate Order reflects the new RRRP charge.

Revenue-to-Cost Ratio Adjustments

Revenue-to-cost ratios measure the relationship between the revenues expected from a class of customers and the level of costs allocated to that class. The Board has established target ratio ranges for electricity distributors in its report *Application of Cost Allocation for Electricity Distributors*, dated November 28, 2007 and in its updated report *Review of Electricity Distribution Cost Allocation Policy,* dated March 31, 2011. Pursuant to the Board’s Decision in its 2012 cost of service application EB-2011-0322, Chapleau PUC proposed to increase the revenue-to-cost ratio for its Sentinel Lighting and Street Lighting classes, offset by a reduction in that of the GS >50 kW class.

The table below outlines the proposed revenue-to-cost ratios.

Current and Proposed Revenue-to-Cost Ratios

Rate Class	Current 2013 Ratio	Proposed 2014 Ratio
Residential	0.97	0.97
General Service Less Than 50 kW	1.04	1.04
General Service 50 to 4,999 kW	1.23	1.22
Street Lighting	0.78	0.80
Sentinel Lighting	0.61	0.68
Unmetered Scattered Load	1.19	1.19

Board staff submitted that the proposed revenue-to-cost ratio adjustments were in accordance with the Board's decision in Chapleau PUC's 2012 cost of service proceeding.

The Board agrees that the proposed revenue-to-cost ratios are consistent with the decision arising from the 2012 cost of service proceeding and therefore approves the revenue-to-cost ratios as filed.

Retail Transmission Service Rates

Electricity distributors are charged for transmission costs at the wholesale level and then pass on these charges to their distribution customers through the Retail Transmission Service Rates ("RTSRs"). Variance accounts are used to capture differences in the rate that a distributor pays for wholesale transmission service compared to the retail rate that the distributor is authorized to charge when billing its customers (i.e. variance Accounts 1584 and 1586).

The Board issued revision 3.0 of the *Guideline G-2008-0001 - Electricity Distribution Retail Transmission Service Rates* (the "RTSR Guideline") which outlines the information that the Board requires electricity distributors to file to adjust their RTSRs for 2014. The RTSR Guideline requires electricity distributors to adjust their RTSRs based on a comparison of historical transmission costs adjusted for the new Uniform Transmission Rates ("UTR") levels and the revenues generated under existing RTSRs. Similarly, embedded distributors must adjust their RTSRs to reflect any changes to the applicable Sub-Transmission RTSRs of their host distributor(s), e.g. Hydro One Networks Inc.

Chapleau PUC is a partially embedded distributor whose host is Hydro One Networks Inc.

The Board issued its Rate Order for Hydro One Transmission (EB-2012-0031) which adjusted the UTRs effective January 1, 2014, as shown in the following table:

2014 Uniform Transmission Rates

Network Service Rate	$3.82 per kW
Connection Service Rates Line Connection Service Rate Transformation Connection Service Rate	 $0.82 per kW $1.98 per kW

The Board also approved new rates for Hydro One Networks' Sub-Transmission class, including the applicable RTSRs, effective January 1, 2014 (EB-2013-0141), as shown in the following table.

2014 Sub-Transmission RTSRs

Network Service Rate	$3.23 per kW
Connection Service Rates Line Connection Service Rate Transformation Connection Service Rate	 $0.65 per kW $1.62 per kW

The Board finds that these 2014 UTRs and Sub-Transmission class RTSRs are to be incorporated into the filing module.

Review and Disposition of Group 1 Deferral and Variance Account Balances

The *Report of the Board on Electricity Distributors' Deferral and Variance Account Review Initiative* provides that, during the IRM plan term, the distributor's Group 1 account balances will be reviewed and disposed if the preset disposition threshold of $0.001 per kWh (debit or credit) is exceeded. The onus is on the distributor to justify why any account balance in excess of the threshold should not be disposed.

Chapleau PUC's 2012 actual year-end total balance for Group 1 accounts including interest projected to April 30, 2014 is a credit of $108,948. This amount results in a total credit claim of $0.0041 per kWh, which exceeds the preset disposition threshold.

Low Voltage Billing Error

Chapleau PUC recorded a principal debit balance of $93,387 and interest of $1,831 in Account 1550 and proposed recovery within its 2012 Group 1 balances to reflect adjusted low voltage charges resulting from a billing error by Hydro One. Chapleau PUC received an invoice for $93,387 from Hydro One in September 2013, which adjusted the billed demand quantity (kW) from January 28, 2009 to April 3, 2013. Chapleau PUC proposed to recover the debit balance with its 2012 deferral and variance account balances to offset the credit balance of $108,948, reducing the total credit balance for disposition to $13,730. This would result in a total credit claim of $0.0005, which does not meet the preset disposition threshold.

Chapleau PUC confirmed that the $93,387 consists of two components:

- $34,296 related to transactions subsequent to December 31, 2011, where the account balance has not yet been disposed on a final basis; and
- $59,091 related to transactions prior to December 31, 2011, where the account balance was approved by the Board and disposed on a final basis in Chapleau PUC's 2013 IRM rate proceeding EB-2012-0114.

Chapleau indicated that it had an internal process for checking the accuracy of amounts payable and that it had questioned Hydro One's billed amounts on three occasions since 2009. Hydro One assured Chapleau PUC that the invoiced amounts were correct. In early 2013, Chapleau PUC again questioned the invoice received and was informed by Hydro One that there was indeed an error.

Board staff submitted that Chapleau PUC's 2011 deferral and variance account balances had been disposed of on a final basis in Chapleau PUC's 2013 IRM decision, and that the proposal to recover the adjustment of $59,091 relating to this period from Chapleau PUC's customers would result in retroactive ratemaking[1].

Board staff submitted that both the Retail Settlement Code and Hydro One's Conditions of Service addressed under-billing situations, limiting the amount of time over which a distributor must be repaid. Specifically, Board staff noted that Section 7.7.7 states the following:

> Where the distributor has under billed a customer or retailer, the maximum period of under billing for which the distributor is entitled to be paid is 2 years. Where the distributor has over billed a customer or retailer, the maximum period of over billing for which the customer or retailer is entitled to be repaid is 2 years.

Board staff also noted in its submission that Hydro One's Conditions of Service provide for recovery of billing errors, as follows:

> Where a billing error, from any cause, has resulted in a Customer or Retailer being under-billed, and where Measurement Canada has not become involved in the dispute, the Customer or Retailer shall pay to Hydro One the amount that was not previously billed. In the case of an individual Customer who is not responsible for the error, the allowable period of time for which the Customer may be charged is two (2) years for residential customers, including seasonal and farm residence, and all other customers[2].

Board staff submitted that Chapleau PUC may choose to consider the Retail Settlement Code and Hydro One's Conditions of Service as a basis by which to pursue further discussions with Hydro One.

VECC submitted that, based on past Board decisions, it would be inappropriate for Chapleau PUC to include an out-of-period adjustment and that the Board should not approve Chapleau PUC's request.

Chapleau PUC included Hydro One's comments in its reply submission. Therein, Hydro

[1] EB-2013-0022, Decision and Order, Veridian Motion to Review, April 25 2013, p. 10

[2] Hydro One Networks Inc. Conditions of Service, May 21, 2013, s. G. Billing Errors, p. 71c

One indicated that its settlement practices with its embedded distributors are consistent with the approach used by the Independent Electricity System Operator with market participants, which incorporates the correction of billing errors without regard to any time limitation. Failure to mirror this approach would result in cross-subsidization and improper allocation of costs among the parties involved.

Chapleau PUC submitted that the disputed amount of $59,091 represents 7.3% of its distribution revenue, and that failure to recover this amount from customers would create a serious cash flow risk. Chapleau PUC submitted that it should not be penalized for Hydro One's error. Chapleau PUC requested that the Board allow it to recover the full amount of $93,387, or the Board should not allow Hydro One to pass on its billing errors, if a distributor is unable to recover those costs from its customers.

The Board cannot approve the proposal to recover the adjustment of $59,091 relating to Chapleau PUC's 2011 deferral and variance account balances. The 2011 account balances were disposed on a final basis in Chapleau PUC's 2013 IRM decision. To subsequently adjust the balances would result in retroactive ratemaking. The courts have made it very clear that retroactive rate-making, the adjustment to rates after a final rate order has been issued, is not allowed. Rather, the principles of certainty and finality are a necessary component of effective rate regulation.

The Board approves the disposition of a debit amount of $34,296 as the account balance has not yet been disposed on a final basis.

Chapleau did not ask for disposition of its Group 1 balances in this proceeding. However, with the exclusion of the $59,091 the disposition threshold is met. In making this decision, the Board is mindful of the efforts made by Chapleau PUC to rectify the Hydro One billing error beginning in 2009. It is through no fault on the part of Chapleau PUC that it is faced with a significant adjustment to its past low voltage payments that cannot be recovered by way of a rate application to the Board.

The Board notes that both the Retail Settlement Code and Hydro One's Conditions of Service in effect during the period of overbilling, and when the invoice was dated, appear to provide some remedy for this situation; however, the onus is on Chapleau to pursue these options. The Board's opinion is that neither Chapleau PUC nor its current customers should pay for costs that go back as far as 2009, given it was solely the result of Hydro One's billing error.

The Board approves the disposition of a credit balance of $73,980 as of December 31, 2012, including interest as of April 30, 2014 for Group 1 accounts. This credit balance includes the additional debit amount of $34,295 in Account 1550 as discussed above. Under normal circumstances, the default period for the disposition of deferral and variance account balances is one year. In this case, in order to mitigate the impact on Chapleau's cash flow, these balances are to be disposed over a two-year period from May 1, 2014 to April 30, 2016.

The table below identifies the principal and interest amounts approved for disposition for Group 1 accounts.

Group 1 Deferral and Variance Account Balances

Account Name	**Account Number**	**Principal Balance A**	**Interest Balance B**	**Total Claim C = A + B**
LV Variance Account	1550	$19,399	($41)	$19,358
RSVA - Wholesale Market Service Charge	1580	($36,071)	($1,512)	($37,583)
RSVA - Retail Transmission Network Charge	1584	$7,449	$507	$7,956
RSVA - Retail Transmission Connection Charge	1586	$635	$413	$1,048
RSVA - Power	1588	($6,511)	($2,766)	($9,277)
RSVA - Global Adjustment	1589	$34,451	$950	$35,401
Recovery of Regulatory Asset Balances	1590	0	0	0
Disposition and Recovery of Regulatory Balances (2008)	1595	0	$135	$135
Disposition and Recovery of Regulatory Balances (2010)	1595	0	($3)	($3)
Disposition and Recovery of Regulatory Balances (2011)	1595	($88,552)	($2,462)	($91,014)
Total Group 1 Excluding Global Adjustment – Account 1589		**($103,651)**	**($5,729)**	**($109,381)**
Total Group 1		**(69,200)**	**($4,779)**	**($73,980)**

The balance of each Group 1 account approved for disposition shall be transferred to the applicable principal and interest carrying charge sub-accounts of Account 1595 pursuant to the requirements specified in Article 220, Account Descriptions, of the *Accounting Procedures Handbook for Electricity Distributors*. The date of the transfer must be the same as the effective date for the associated rates, generally, the start of the rate year. Chapleau PUC should ensure these adjustments are included in the reporting period ending June 30, 2014 (Quarter 2).

Low Voltage Rates

Chapleau PUC withdrew its request to change its low voltage rates, and stated that it would address these changes in its next cost of service application.

Rate Model

With this Decision and Rate Order, the Board is providing Chapleau PUC with a rate model, applicable supporting models and a draft Tariff of Rates and Charges (Appendix A). The Board also reviewed the entries in the rate model to ensure that they were in accordance with the 2013 Board-approved Tariff of Rates and Charges and the rate model was adjusted, where applicable, to correct any discrepancies.

THE BOARD ORDERS THAT:

1. Chapleau PUC's new distribution rates shall be effective May 1, 2014.

2. Chapleau PUC shall review the draft Tariff of Rates and Charges set out in Appendix A and shall file with the Board, as applicable, a written confirmation of its completeness and accuracy, or provide a detailed explanation of any inaccuracies or missing information, within **7 days** of the date of issuance of this Decision and Rate Order.

3. If the Board does not receive a submission from Chapleau PUC to the effect that inaccuracies were found or information was missing pursuant to item 2 of this Decision and Rate Order, the draft Tariff of Rates and Charges set out in Appendix A of this Decision and Rate Order will become final. Chapleau PUC shall notify its customers of the rate changes no later than the delivery of the first bill reflecting the new rates.

4. If the Board receives a submission from Chapleau PUC to the effect that inaccuracies were found or information was missing pursuant to item 2 of this Decision and Rate Order, the Board will consider the submission of Chapleau PUC prior to issuing a final Tariff of Rates and Charges.

5. Chapleau PUC shall pay the Board's costs incidental to this proceeding upon receipt of the Board's invoice.

COST AWARDS

The Board will issue a separate decision on cost awards once the following steps are completed:

1. VECC shall submit its cost claims no later than **7 days** from the date of issuance of the final Rate Order.

2. Chapleau PUC shall file with the Board and forward to VECC any objections to the claimed costs within **21 days** from the date of issuance of the final Rate Order.

3. VECC shall file with the Board and forward to Chapleau PUC any responses to any objections for cost claims within **28 days** from the date of issuance of the final Rate Order.

4. Chapleau PUC shall pay the Board's costs incidental to this proceeding upon receipt of the Board's invoice.

All filings to the Board must quote file number **EB-2013-0119,** be made through the Board's web portal at https://www.pes.ontarioenergyboard.ca/eservice/ and consist of two paper copies and one electronic copy in searchable / unrestricted PDF format. Filings must clearly state the sender's name, postal address and telephone number, fax number and e-mail address. Parties must use the document naming conventions and document submission standards outlined in the RESS Document Guideline found at www.ontarioenergyboard.ca. If the web portal is not available parties may email their document to BoardSec@ontarioenergyboard.ca. Those who do not have internet access are required to submit all filings on a CD in PDF format, along with two paper copies. Those who do not have computer access are required to file 2 paper copies.

DATED at Toronto, March 13, 2014
ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

Appendix A

To Decision and Rate Order

Draft Tariff of Rates and Charges

Board File No: EB-2013-0119

DATED: March 13, 2014

Chapleau Public Utilities Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2014

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2013-0119

RESIDENTIAL SERVICE CLASSIFICATION

This classification refers to an account taking electricity at 750 volts or less where the electricity is used exclusively by a single family unit, non-commercial. This can be a separately metered living accommodation, town-house, apartment, semi-detached, duplex, triplex or quadruplex with residential zoning. Further servicing details are available in the distributor's Condition of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor’s Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	23.77
Rate Rider for Disposition of Residual Historical Smart Meter Costs - effective until April 30, 2016	$	2.26
Rate Rider for Disposition of Stranded Meter Assets - effective until April 30, 2016	$	0.90
Rate Rider for Smart Metering Entity Charge - effective until October 31, 2018	$	0.79
Distribution Volumetric Rate	$/kWh	0.0138
Low Voltage Service Rate	$/kWh	0.0006
Rate Rider for Disposition of Deferral/Variance Accounts (2012) - effective until April 30, 2016	$/kWh	(0.0034)
Rate Rider for Disposition of Deferral/Variance Accounts (2013) - effective until April 30, 2015	$/kWh	0.0036
Rate Rider for Disposition of Global Adjustment Sub-Account (2013) - effective until April 30, 2015		
Applicable only for Non-RPP Customers	$/kWh	(0.0021)
Rate Rider for Disposition of Deferral/Variance Accounts (2014) - effective until April 30, 2016	$/kWh	(0.0021)
Rate Rider for Disposition of Global Adjustment Account (2014) - effective until April 30, 2016		
Applicable only for Non-RPP Customers	$/kWh	0.0024
Retail Transmission Rate - Network Service Rate	$/kWh	0.0069
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0016

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0013
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Chapleau Public Utilities Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2014

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2013-0119

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification refers to a non residential account taking electricity at 750 volts or less whose average monthly average peak demand is less than, or is forecast to be less than, 50 kW. Further servicing details are available in the distributor's Condition of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor’s Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	34.78
Rate Rider for Disposition of Residual Historical Smart Meter Costs - effective until April 30, 2016	$	3.29
Rate Rider for Disposition of Stranded Meter Assets - effective until April 30, 2016	$	1.64
Rate Rider for Smart Metering Entity Charge - effective until October 31, 2018	$	0.79
Distribution Volumetric Rate	$/kWh	0.0177
Low Voltage Service Rate	$/kWh	0.0006
Rate Rider for Disposition of Deferral/Variance Accounts (2012) - effective until April 30, 2016	$/kWh	(0.0030)
Rate Rider for Disposition of Deferral/Variance Accounts (2013) - effective until April 30, 2015	$/kWh	0.0036
Rate Rider for Disposition of Global Adjustment Sub-Account (2013) - effective until April 30, 2015		
Applicable only for Non-RPP Customers	$/kWh	(0.0021)
Rate Rider for Disposition of Deferral/Variance Accounts (2014) - effective until April 30, 2016	$/kWh	(0.0021)
Rate Rider for Disposition of Global Adjustment Account (2014) - effective until April 30, 2016		
Applicable only for Non-RPP Customers	$/kWh	0.0024
Retail Transmission Rate - Network Service Rate	$/kWh	0.0061
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0016

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0013
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Chapleau Public Utilities Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2014

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2013-0119

GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION

This classification refers to a non-residential account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 kW. Further servicing details are available in the distributor's Condition of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor’s Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	192.00
Rate Rider for Disposition of Residual Historical Smart Meter Costs - effective until April 30, 2016	$	6.10
Distribution Volumetric Rate	$/kW	3.5875
Low Voltage Service Rate	$/kW	0.2256
Rate Rider for Disposition of Deferral/Variance Accounts (2012) - effective until April 30, 2016	$/kW	(0.7046)
Rate Rider for Disposition of Deferral/Variance Accounts (2013) - effective until April 30, 2015	$/kW	1.4064
Rate Rider for Disposition of Global Adjustment Sub-Account (2013) - effective until April 30, 2015		
Applicable only for Non-RPP Customers	$/kW	(0.8225)
Rate Rider for Disposition of Deferral/Variance Accounts (2014) - effective until April 30, 2016	$/kW	(0.8028)
Rate Rider for Disposition of Global Adjustment Account (2014) - effective until April 30, 2016		
Applicable only for Non-RPP Customers	$/kW	0.9020
Retail Transmission Rate - Network Service Rate	$/kW	2.5339
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	0.5811

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0013
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Chapleau Public Utilities Corporation
TARIFF OF RATES AND CHARGES
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EB-2013-0119

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification refers to an account taking electricity at 750 volts or less whose monthly average peak demand is less than, or is forecast to be less than, 50 kW and the consumption is un-metered. Such connections include cable TV, power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The customer will provide detailed manufacturer information/documentation with regard to electrical demand/consumption of the proposed unmetered load. Further servicing details are available in the distributor's Condition of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor’s Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	24.71
Distribution Volumetric Rate	$/kWh	0.0332
Low Voltage Service Rate	$/kWh	0.0006
Rate Rider for Disposition of Deferral/Variance Accounts (2012) - effective until April 30, 2016	$/kWh	(0.0177)
Rate Rider for Disposition of Deferral/Variance Accounts (2013) - effective until April 30, 2015	$/kWh	0.0036
Rate Rider for Disposition of Deferral/Variance Accounts (2014) - effective until April 30, 2016	$/kWh	(0.0029)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0061
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0016

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0013
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Chapleau Public Utilities Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2014

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EB-2013-0119

SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light. Further servicing details are available in the distributor's Condition of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	7.84
Distribution Volumetric Rate	$/kW	13.6395
Low Voltage Volumetric Rate	$/kW	0.2261
Rate Rider for Disposition of Deferral/Variance Accounts (2012) - effective until April 30, 2016	$/kW	(2.5846)
Rate Rider for Disposition of Deferral/Variance Accounts (2013) - effective until April 30, 2015	$/kW	1.4191
Rate Rider for Disposition of Deferral/Variance Accounts (2014) - effective until April 30, 2016	$/kW	(0.8234)
Retail Transmission Rate - Network Service Rate	$/kW	1.9208
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	0.4587

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0013
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Chapleau Public Utilities Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2014

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EB-2013-0119

STREET LIGHTING SERVICE CLASSIFICATION

This classification refers to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting operation, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape template. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	4.38
Distribution Volumetric Rate	$/kW	20.3873
Low Voltage Service Rate	$/kW	0.2173
Rate Rider for Disposition of Deferral/Variance Accounts (2012) - effective until April 30, 2016	$/kW	(1.6069)
Rate Rider for Disposition of Deferral/Variance Accounts (2013) - effective until April 30, 2015	$/kW	1.3550
Rate Rider for Disposition of Deferral/Variance Accounts (2014) - effective until April 30, 2016	$/kW	(0.7525)
Retail Transmission Rate - Network Service Rate	$/kW	1.9111
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	0.4493

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0013
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Chapleau Public Utilities Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2014

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EB-2013-0119

microFIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	5.40

Chapleau Public Utilities Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2014

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EB-2013-0119

ALLOWANCES

Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.60)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

SPECIFIC SERVICE CHARGES

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

Customer Administration

Arrears certificate	$	15.00
Credit Reference/credit check (plus credit agency costs)	$	15.00
Returned cheque charge (plus bank charges)	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Special meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00

Non-Payment of Account

Late Payment – per month	%	1.50
Late Payment – per annum	%	19.56
Collection of account charge – no disconnection	$	30.00
Disconnect/Reconnect at meter – during regular hours	$	65.00

Install/Remove load control device – during regular hours	$	65.00
Specific Charge for Access to the Power Poles - $/pole/year	$	22.35

Chapleau Public Utilities Corporation

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2014

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2013-0119

RETAIL SERVICE CHARGES (if applicable)

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity.

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	100.00
Monthly Fixed Charge, per retailer	$	20.00
Monthly Variable Charge, per customer, per retailer	$/cust.	0.50
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.30)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.25
Processing fee, per request, applied to the requesting party	$	0.50
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year	$	no charge
More than twice a year, per request (plus incremental delivery costs)	$	2.00

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0654
Distribution Loss Factor - Secondary Metered Customer < 5,000 kW	1.0506

11

Ontario

EB-2013-0022

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c.15 (Schedule B);

AND IN THE MATTER OF an application by Veridian Connections Inc. for an order or orders approving or fixing just and reasonable distribution rates related to Smart Meter deployment, to be effective November 1, 2012.

AND IN THE MATTER OF a Motion to Review and Vary by Veridian Connections Inc. pursuant to the Ontario Energy Board's *Rules of Practice and Procedure* for a review by the Board's Decision and Order in proceeding EB-2012-0247.

BEFORE: Marika Hare
Presiding Member

DECISION AND ORDER ON MOTION TO REVIEW

April 25, 2013

INTRODUCTION

On January 23, 2013, Veridian Connections Inc. ("Veridian") filed with the Ontario Energy Board (the "Board") a motion for request to review and vary (the "Motion") the Board's Decision and Order dated October 25, 2012 (the "Decision") in respect of Veridian's smart meter application (EB-2012-0247) (the "Final Disposition Proceeding"). The Board assigned the Motion file number EB-2013-0022.

The Motion sought to extend the time for filing the Motion with the Board and vary the

Board's EB-2012-0247 Decision to permit Veridian to recover an additional $478,224 in revenue requirement related to 2009 amortization expenses associated with smart meter capital expenditures made in 2006, 2007, and 2008. The recovery is to be made through amendment of the existing Smart Meter Disposition Riders ("SMDRs") commencing on May 1, 2013 and continuing until April 30, 2014.

The Board issued its Notice of Motion to Vary and Procedural Order No. 1 on March 6, 2013. The Board granted intervenor status and cost award eligibility to the Vulnerable Energy Consumers Coalition ("VECC"), as it was the only intervenor in Veridian's smart meter rate proceeding under EB-2012-0247. The Board also determined that the most expeditious way of dealing with the Motion was to consider concurrently the threshold question of whether the matter should be reviewed, as contemplated in the Board's *Rules of Practice and Procedure* (the "Rules"), and the merits of the Motion.

The Board established a timetable for Veridian to file any additional material in support of the Motion, followed by written submissions by VECC and Board staff, and a reply submission by Veridian.

Veridian submitted additional material in support of its Motion on March 13, 2013. Board staff filed its submission on March 22, 2013. Veridian filed its reply submission on April 3, 2013. VECC did not file any submission.

For the reasons that follow the Board grants the extension of time for filing the Motion and finds that the threshold test has been met. The Board has reviewed the Motion materials and the Decision, and for the reasons set out below has determined that it will not grant the relief requested.

BACKGROUND

On October 2, 2009 Veridian applied to the Board for approval of 2010 rates on a Cost of Service basis (EB-2009-0140) (the "Interim Disposition Proceeding"), within which Veridian applied for interim disposition of smart meter-related revenue requirement amounts. As part of the Interim Disposition Proceeding, the capital expenditures associated with smart meter investments up to December 31, 2008 were included in Veridian's rate base effective January 1, 2010. Accordingly, going forward from January 1, 2010, the revenue requirement associated with smart meter capital expenditures up to December 31, 2008 was included in base rates.

Even after taking into account the interim clearance of smart meter amounts as approved by the Board in the Interim Disposition Proceeding, the 2009 amortization amounts related to smart meter capital investments made prior to January 1, 2009 were neither: a) included in base rates; nor b) recovered as part of the interim clearance.[1]

The Smart Meter Model (the "Model") issued by the Board along with Guideline G-2011-0001: Smart Meter Meter Funding and Cost Recovery – Final Disposition, issued December 15, 2011, and used by Veridian in its smart meter application EB-2012-0247 did not specifically address the fact that the 2009 amortization related to the pre-2009 smart meter capital expenditures remained outstanding and unrecovered either through an earlier rate rider or through approved distribution rates.

On May 31, 2012, Veridian applied for final disposition of smart meter-related amounts under Board file number EB-2012-0247. As part of that proceeding Veridian used the Board's Model to calculate the revenue requirement to be cleared.

The application sought approval for the final disposition of Account 1555 and 1556 related to smart meter expenditures. Veridian requested SMDRs and Smart Meter Incremental Revenue Requirement Rate Riders ("SMIRRs") effective November 1, 2012.

On October 25, 2012, the Board issued its Decision in the EB-2012-0247 proceeding and found that Veridian's documented costs, as revised in responses to interrogatories, related to smart meter procurement, installation and operation were reasonable. The Board approved the recovery of the costs for smart meter deployment and operation as of December 31, 2011. The Board directed Veridian to establish the SMDRs based on an 18-month recovery period to April 30, 2014, and to accommodate within the SMDR the applicable SMIRR amount related to the period from May 1, 2012 to October 31, 2012.

Veridian filed its Draft Rate Order and provided the following summary table outlining the SMDR and SMIRR rate riders as originally filed, as revised as per interrogatories and as recalculated pursant to the Board's Decision.

[1] Motion for Request for Review and Variance filed by Veridian, January 23, 2013, paragraphs 5 & 6

Class	SMDR ($/month for 18 months)			SMIRR ($/month until new rates set under rebasing)		
	As Filed	Update-Board Staff IR#13	Update - Board Decision	As Filed	Update-Board Staff IR#13	Update - Board Decision
Residential	$0.97	$0.83	$0.55	$0.98	No Change	$ 1.25
GS < 50 kW	$2.45	$4.15	$3.45	$2.46	No Change	$ 3.17

Board staff filed comments on the draft Rate Order on November 5, 2012 and agreed that Veridian had appropriately reflected the Board's findings in its draft Rate Order and proposed Tariff of Rates and Charges.

The Board issued Veridian's final Rate Order on November 15, 2012.

Veridian is now asking the Board through its Motion to allow for recovery of smart meter capital expenditures in the amount of $478,224, inclusive of Payment In Lieu of Taxes ("PILs") impacts, through the amendment of the existing SMDR. The amended SMDR is proposed to commence on May 1, 2013 and to continue until April 30, 2014.

Issues Before the Board

1. Extension of time

As noted by Veridian in its Motion materials, Veridian discovered the gap in recovery of smart meter expenses on January 9, 2013 during preparation of its regular year-end accounting working papers. It was during this process that Veridian realized that, with respect to the costs incurred by Veridian in relation to smart meter implementation it had not yet recovered the 2009 amortization expense related to pre-2009 smart meter capital expenditures, totalling $528,859 (before accounting for PILs impacts) and recorded in Account 1556.

As a result of the timing of Veridian's discovery of this amount for which it had not sought recovery it was not in a position to file its Motion within the prescribed 20 days specified in the Rules, which expired on or about November 14, 2012. Accordingly, Veridian asks that the Board use its discretion to extend the time period for filing a request for review.

The Board notes that parties are expected to respect the Board's deadlines and comply with the Rules, however the Board understands that the error was not identified by Veridian until after the 20 day period had expired and Veridain filed its motion immediately after becoming aware of the error. The Board therefore will use its discretion to hear the Motion, despite the timelines being exceeded.

2. Motion to Review and Vary

Veridian's Motion seeks to vary the Decision so that Veridian may recover an additional $478,224 in revenue requirement related to 2009 amortization expense of $528,859 associated with smart meter capital expenditures made in 2006, 2007, and 2008, less a credit to Grossed-up Taxes/PILs of $50,635.

Veridian requests revisions to its SMDR as outlined below.

Rate Class	Currently Approved Rate Rider	Requested Revision to Rate Rider effective May 1, 2013
Residential	$0.55	$0.83
Residential – Urban Year Round	$0.55	$0.83
Residential – Suburban Year Round	$0.55	$0.83
General Service Less Than 50 kW	$3.45	$4.59

Veridian bases its Motion on the following grounds:

1. There is an identifiable error in the Decision and that there are inconsistent findings in the Decision. The error is material and relevant to the outcome of the Decision. The omission of the 2009 amortization is a calculation error that should be remedied through a variance of the original Decision.

2. Veridian also notes that as part of the EB-2012-0247 proceeding, Veridian completed the Board's Model to calculate the revenue requirement to be recovered. However, the Model, in its design, did not anticipate any gap (i.e., unrecovered amounts from a reviewed and approved interim recovery, and final disposition of smart meter-related amounts in relation to amortization expense of installed smart meters.

The Threshold Test

The application of the threshold test was considered by the Board in its Decision on a Motion to Review the Natural Gas Electricity Interface Review Decision (the "NGEIR Review Decision"). The Board, in the NGEIR Review Decision, stated that the purpose of the threshold question is to determine whether the grounds put forward by the moving party raise a question as to the correctness of the order or the decision, and whether there is enough substance to the issues raised such that a review based on those issues could result in the Board varying, cancelling, or suspending the decision. Further, in the NGEIR Decision, the Board indicated that in order to meet the threshold question there must be an “identifiable error” in the decision for which review is sought and that “the review is not an opportunity for a party to reargue the case”.

In addition to the test set out in the NGEIR Review Decision, Rule 45.01of the Board’s Rules provides that, with respect to a motion for review the Board may determine, with or without a hearing, a threshold question whether the matter should be reviewed before conducting any review on the merits.

Rule 44.01(a) sets out some of the grounds upon which a motion may be raised with the Board:

> Every notice of motion made under Rule 42.01, in addition to the requirements under Rule 8.02, shall:
>
> > (a) Set out the grounds for the motion that raise a question as to the correctness of the order or decision, which grounds may include:
> > i. error in fact;
> >
> > ii. change in circumstances;
> >
> > iii. new facts that have arisen;
> >
> > iv. facts that were not previously placed in evidence in the proceeding and could not have been discovered by reasonable diligence at the time.

The Board also notes that in the NGEIR Review Decision it was established that the Board has the necessary discretion to supplement the above list of grounds upon which a motion to review and vary may be raised in an appropriate case.[2]

[2] EB-2006-0322/EB-2006-0338/EB-2006-0340, Motions to Review the Natural Gas Electricity Interface Review Decision, May 22, 2007, page 15

The Board received submissions from Veridian and Board staff. Board staff submitted that the threshold test has not been met arguing that none of the grounds listed in Rule 44.01 had been established. Veridian argued that the threshold had been met and that the Motion had merit.

The Board discusses each of the grounds set out in Rule 44.01 below with respect to the facts as presented in this Motion.

i. Error in fact

Veridian argued that a combination of what it would characterize as unusual circumstances relating to the multi-proceeding approach to the recovery of its smart meter-related revenue requirement led to an error in the calculation of the rider that was intended to fully compensate Veridian for costs incurred in the deployment and operation of smart meters. Veridian also submitted that the error related to the failure of the SMDR to compensate Veridian for 2009 Amortization Expenses related to 2006, 2007, and 2008 smart meter Capital Expenses in the amount of $478,223.79.

Veridian stated that the error it is seeking to have corrected is not related to the omission of evidence that, had it been before the Board prior to the Decision may or may not have influenced the exercise of the Board's discretion or judgment with respect to the prudence of Veridian's smart meter-related expenditures. Veridian noted that it is asking the Board to correct a clear error in the calculation of the recovery that necessarily follows from the Board's analysis of the prudence of Veridian's spending.

Board staff submitted that in demonstrating that there is an error, the applicant must be able to show that the findings are contrary to the evidence that was before the panel, that the panel failed to address a material issue, that the panel made inconsistent findings, or something of a similar nature. Board staff submitted that the Board's Decision is consistent with the evidence provided by Veridian.

Veridian argued in its reply submission that Board staff has admitted that there is an error in the Decision when it accepted that the $478,223.79 amount should have been factored into the SMDR calculation as it is an outcome of the smart meter capital expenditures approved by the Board.

The Board finds that Veridian has failed to demonstrate that the findings are contrary to the evidence that was before the Panel, that the Panel failed to address a material issue or that the Panel made inconsistent findings. The Board finds that the Decision was correct based on the evidence presented by Veridian in its pre-filed materials and during the proceeding.

ii. Change in circumstances

The Board finds no change in circumstances and notes that neither Veridian nor Board staff made any submissions with respect to this aspect of the threshold test.

iii. New facts that have arisen

Both Board staff and Veridian acknowledged that the review of accounting year-end working papers did result in the discovery of the amount of $478,224 now claimed by Veridian. The amortization expenses claimed in this Motion are for the previously installed and approved smart meters for the discrete time period of 2009. The Board notes that these amounts were at the time both unaudited and outside of the test year for 2010 rates.

In its submission Board staff noted that Veridian is asking the Board to address a calculation error that was made when implementing the Board's approval of Veridian's smart meter capital expenditures through an SMDR.

Board staff acknowledged that the Model did not explicitly contemplate Veridian's circumstances, but submitted that the use of the Model does not preclude the need for other calculations to accommodate the special circumstances of any particular distributor or its application. Further, Board staff submitted that Veridian should have been aware that there was an amount missing prior to filing its application, as the expenses documented in the Model would have been diferent than the principal balances in Account 1556 for OM&A, and specifically, depreciation. Veridian was in the best position to identify the missing depreciation expense during that proceeding and it should not be incumbent on the Board, Board staff, or VECC as the intervenor to recognize this oversight.

Veridian stated that it only discovered the gap in recovery of smart meter expenses on January 9, 2013 during preparation of its regular year-end accounting working papers. It was during this process that Veridian realized that, with respect to the costs incurred by Veridian in relation to smart meter implementation it had not yet recovered the 2009 amortization expense related to pre-2009 smart meter capital expenditures, totalling $528,859 (before accounting for PILs impacts) and recorded in Account 1556.

Veridain submitted that the omission of the 2009 amortization is a calculation error that constitutes a new fact and that the omission of the $478,224 should be remedied through a variance of the original Decision.

The Board finds that this is a new fact for the purpose of the threshold test. This amount was not previously in evidence, nor was the fact that amortization for 2009 had never been addressed nor that the total amount in the account was not cleared. The Board therefore finds that the threshold test for reviewing the Decision has been met.

The Merits of the Motion

Both Board staff and Veridian agree that the amount of $478,224 that Veridian is now seeking recovery of in its Motion is both material and is not in dispute. It is also submitted by Veridian and agreed to by Board staff that the amount should have been factored into the SMDR calculation as it is an outcome of the smart meter capital expenditures approved by the Board.

The Board notes that it has been consistent in allowing for the full recovery of the prudently incurred revenue requirement for approved smart meters deployed in accordance with the Government's regulations.[3] However, the Board finds that the failure to include the $478,224 for recovery in the EB-2012-0247 proceeding was an error on the part of Veridian. Veridian itself submitted that it was an omission to not include the 2009 amortization expenses.

Previous decisions of the Board when dealing with distributors' errors in calculations have resulted in disallowance of the correction, when in the distributor's favour. For example, in the North Bay Hydro decision[4] the Board found that "[t]he utility has control of its books and records and has the responsibility to ensure mistakes do not occur." As a result, the Board in that decision denied the application of North Bay Hydro.

The Board finds some parallels in this situation. Veridian should have been aware of

[3] EB-2012-0081, Cambridge and North Dumfries Hydro Inc., July 26, 2012, page 9
[4] EB-2009-0113, North Bay Distribution Ltd., September 8, 2009

the correct amount of the smart meter expenditures, including amortization expenses. The Board's Guideline G-2011-0001 and Smart Meter Model make it clear that it is the responsibility of the distributor to amend the models as appropriate.[5] The Board expects a utility to provide the Board with accurate accounting for rate setting purposes. Veridian has control of its books and records and has the responsibility to ensure mistakes do not occur. The Board will not adjust for this error.

A second very important factor is with respect to retroactive rate-making. If the Board were to allow recovery this would result in retroactive ratemaking in that Veridian is asking to recover an additional $478,224 in revenue requirement related to 2009 amortization expense through revisions to the SMDR which were established in a Final Rate Order. The courts have made it very clear that retroactive rate-making, the adjustment to rates after a final rate order has been issued, is not allowed. Rather, the principles of certainty and finality are a necessary component of effective rate regulation. To allow Veridian to correct a calculation error after a final rate order was issued would require the Board to engage in retroactive ratemaking, which is contrary to the legal principles upon which the Board performs its legislated mandate.

DATED at Toronto, April 25, 2013
ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

[5] Guideline G-2011-0001 and the associated Board-issued models contemplate that a smart meter cost recovery application will cover all costs up to and including the prospective test year to appropriate calculate the SMDR and SMIRR to recover all historical and prospective costs until the distributor's next cost of service application. This thus consists of both audited and unaudited actuals historically and to the bridge year, and forecasts for part of the bridge and test years. This avoids the need for a further application to review audited stub period costs.

12

In the Court of Appeal of Alberta

Citation: ATCO Gas and Pipelines Ltd v Alberta (Utilities Commission), 2014 ABCA 397

Date: 20141202
Dockets: 1301-0069-AC
1301-0070-AC
Registry: Calgary

1301-0069-AC

Between:

ATCO Gas and Pipelines Ltd. and ATCO Electric Ltd.

Appellants

- and -

Alberta Utilities Commission

Respondent

1301-0070-AC

And Between:

ATCO Gas and Pipelines Ltd. and ATCO Electric Ltd.

Appellants

- and -

Alberta Utilities Commission and
Office of the Utilities Consumer Advocate of Alberta

Respondents

The Court:

The Honourable Chief Justice Catherine Fraser
The Honourable Mr. Justice Jean Côté
The Honourable Mr. Justice Peter Martin

Reasons for Judgment Reserved of The Honourable Chief Justice Fraser

Reasons for Judgment Reserved of The Honourable Mr. Justice Côté Concurring in the Result

Reasons for Judgment Reserved of The Honourable Mr. Justice Martin Dissenting in Part

Appeal from the Alberta Utilities Commission
in Application No. 1566373, Proceeding ID No. 20
Dated the 20th day of February, 2013

Appeal from the Alberta Utilities Commission
Decision 2013-051
Dated the 20th day of February, 2013

Reasons for Judgment Reserved of The Honourable Chief Justice Fraser

I. Introduction

[1] In Alberta, the regulatory compact, which involves a balancing of the interests of utility companies and their customers, has its limits. And this case demonstrates one of them. The roots of the regulatory compact, as it has been dubbed, can be found in the 19th century and the emergence of public utility regulation in North America. That regulation was designed to prevent the abuse of monopolistic powers by utility companies. The shape and content of the regulatory compact were initially developed through the common law. Later, as in Alberta, legislators in individual jurisdictions statutorily defined the specific terms governing its scope.

[2] The general concept is that in return for the undertaking to serve all customers in a defined service area, the utility is granted an *opportunity* both to earn a reasonable return on its prudent investment and to recover its prudently incurred expenses. However, the regulatory compact was never an arrangement under which utility companies were entitled to find pockets deeper than their own – their ratepayers – in order to recover every expense incurred in pursuit of their corporate and shareholders' interests. Put simply, the regulatory compact did not confer on utilities an absolute guarantee that they would be entitled to recover all incurred costs and expenses, reasonable or otherwise.

[3] Moreover, the terms of the regulatory compact have always been subject to evolution and the re-balancing of competing interests of consumers and utility companies when times and circumstances change. This is as it should be, especially in this era of deregulation of the gas and electrical sectors in Alberta. There is no industry today that is immune to change. Or that enjoys a *right* to be protected from the consequences of change, whether those arise from legislative choices, deregulation or court decisions.

[4] These appeals by the appellants, ATCO Gas and Pipelines Ltd. (ATCO Gas) and ATCO Electric Ltd. (collectively ATCO Utilities) relate to decisions made by the Alberta Utilities Commission (Commission) in two separate proceedings about legal and consulting costs (collectively legal costs) claimed by the ATCO Utilities. It is important to keep in mind what these appeals are about. Leave was granted on a single common issue and, accordingly, it was directed that the two appeals be heard together. In ***Atco Gas and Pipelines Ltd v Alberta (Utilities Commission)***, 2013 ABCA 331 at para 31, Conrad JA granted leave on the following question:

> Did the Commission err in law or jurisdiction by denying or limiting recovery of the Appellants' claimed regulatory costs and

by treating the costs of or incidental to any hearing or other proceeding of the Commission differently than other costs?

[5] What is not at issue on these appeals is whether the actual amounts of the costs awards themselves were reasonable. The factums filed by the ATCO Utilities on both appeals were dedicated in their entirety to the question of whether the Commission possessed a separate authority to award legal costs. No suggestion was made that, if this were so, the costs awards that the Commission actually made were themselves unreasonable.

[6] For the reasons that follow, I would dismiss both appeals. The common issue appears deceptively simple. It is anything but. These appeals serve as a cautionary example of the complexity associated with the regulation of the utilities sector and why courts should be circumspect before interfering with decisions of expert tribunals. They raise a number of linked issues that go directly to the heart of the Commission's authority to regulate Alberta's utilities sector. In particular, did the Alberta government give the Commission the authority to determine the legal costs of regulated utility companies in proceedings before it? If so, does the Commission have the discretion to award – or not award – legal costs as it considers reasonable? Or is the Commission required by statute or under the regulatory compact to award the utility companies their legal costs in all proceedings before it providing those costs meet the "prudently incurred" standard inherent in that compact? What are the terms of the regulatory compact as statutorily prescribed in Alberta? And what impact has deregulation had on the scope of legal proceedings before the Commission?

[7] To understand what is at stake and why I have concluded that the Commission did not err in its ultimate decisions to both partially deny and partially limit the legal costs of the ATCO Utilities in one hearing and partially limit them in another, I must untangle a complex set of facts. These relate not only to the proceedings that led to these appeals but to other proceedings before the Commission and other court decisions as well.

[8] I begin with the historical and statutory framework (Part II). I next outline the relevant background facts relating to each Commission proceeding after first providing a general overview (Part III). I then address the standard of review and explain why the Commission's decision that it has a separate authority to determine the legal costs, if any, payable to parties in proceedings before it is to be reviewed for reasonableness, not correctness (Part IV). That is followed by a detailed analysis of why the Commission's interpretation of its authority to make costs awards is reasonable (Part V). Finally, I confirm that the appeals should be dismissed (Part VI).

II. Historical and Statutory Framework

[9] The Commission was created on January 1, 2008 by the *Alberta Utilities Commission Act*, SA 2007, c A-37.2 (*Act*). The Commission's earliest predecessor was the Alberta Board of Public Utilities Commissions (PUB) created in 1915. The PUB has had a long and storied history

in Alberta. It was Alberta's first regulatory agency with the primary responsibility to regulate utility rates and services.[1] That included not only the electric utility sector but also the natural gas utility sector.

[10] The *Gas Utilities Act*, passed initially in 1960, remains a major piece of legislation governing the Commission's jurisdiction.[2] In 1985, the price of natural gas, but not the transmission or distribution of natural gas, was deregulated by a federal-provincial agreement.[3]

[11] In 1995, the PUB was merged with the Energy Resources Conservation Board (ERCB) to create the Alberta Energy and Utilities Board (EUB). The purpose was to create a more streamlined regulatory process. Although both the PUB and ERCB remained as separate entities, the EUB was invested with all the powers and rights of the PUB and the ERCB.[4] In addition, the EUB was given the power to act on its own initiative or motion: s. 10(2), *Alberta Energy and Utilities Board Act*, SA 1994, c A-19.5 (*EUB Act*). The members of the EUB were the members of the ERCB and the PUB: s. 3(1), *EUB Act*. The EUB had the right to delegate any of its powers and duties to the PUB or ERCB unless regulations prohibited that delegation: s. 12, *EUB Act*.

[12] The creation of the EUB in 1995 coincided with the Alberta government's adoption of legislation that same year to "deregulate" or more precisely, restructure, certain aspects of the electric energy industry in Alberta.[5] That deregulation began with the enactment of the *Electric Utilities Act*, SA 1995, c E-5.5. Given the changes in the *Electric Utilities Act*, the EUB held a hearing in 1996 to restructure electric tariffs. At that point, the major utility companies applied to separate their generation, transmission and distribution services. That led in turn to further restructuring in accordance with the *Electric Utilities Amendment Act*, SA 1998, c 13. Other

[1] It also exercised authority over a wide range of other matters including supervising debentures issued by municipalities, regulating the sale of securities within Alberta, approving tariffs for provincial railways, approving highway crossings by railway branch lines and governing rates for Alberta's only telecommunications company at the time, namely Alberta Government Telephones. Its authority to regulate a wider range of services was expanded through the years. Later, in 1938, Alberta created the Petroleum and Natural Gas Conservation Board to focus on Alberta's energy resources. However, pipeline regulation remained within the PUB's authority.

[2] SA 1960, c 37. The PUB started regulating gas and electricity rates long before the 1960 *Gas Utilities Act* or the 1995 *Electric Utilities Act*.

[3] Prior to 1985, the price of natural gas was set by agreements between Canada and Alberta. Then on October 31, 1985, Canada and Alberta signed the Natural Gas Markets and Pricing Agreement which became known as the Halloween Agreement. Under this Agreement, natural gas prices are now determined by the market. Since 2004, Albertans may choose to purchase their natural gas from a "Regulated Retailer" that is regulated by the Commission or from a "Competitive Retailer" that is not. Utilities are not permitted to make a profit on the supply cost of gas. For more details, see "Alberta's Energy Market" on the Commission website at http://www.auc.ab.ca/market-oversight/albertas-energy-market/Pages/default.aspx.

[4] The immediate predecessor to the ERCB had been the Oil and Gas Conservation Board whose origins lay in the Petroleum and Natural Gas Conservation Board created in 1938 to conserve Alberta's energy resources and ensure their orderly development.

[5] For an excellent article providing a summary of electric deregulation in Alberta, see Terra Nicolay, "Regulation by Any Other Name: Electricity Deregulation in Alberta and the Power Purchase Agreements" (2011) 29:1 J Energy & Nat'l Res L 45.

legislative refinements were made in 2003 with the *Electric Utilities Act*, SA 2003, c E-5.1. Of particular note, as of 2001, the EUB no longer regulated wholesale electricity prices in Alberta.

[13] Late in 2007, the Legislature decided that the EUB's functions would once again be performed by two separate bodies, the Commission and the ERCB. Thus, as of January 1, 2008, the Commission began its operations in accordance with the *Act*. Like the EUB, the Commission was given the power to act on its own initiative or motion. In addition to regulating utilities, the Commission was also given jurisdiction over hydroelectric projects, power plants, and transmission lines: see *Hydro and Electric Energy Act*, RSA 2000, c H-16.[6] At the same time, the ERCB, which, like the PUB, had continued to exist throughout the term of the EUB, once again began to discharge the duties it had to govern the oil and gas sector. Then, in 2013, the *Energy Resources Conservation Act*, RSA 2000, c E-10 was repealed by the *Responsible Energy Development Act*, SA 2012, c R-17.3 (*REDA*), which replaced the ERCB with the Alberta Energy Regulator.[7]

[14] In summary, prior to 1995 when the EUB was created, utility regulation was within the domain of the PUB. Effective as of 2008 and continuing to this day, the Commission, as the successor to the PUB and the EUB, regulates Alberta's utilities sector through numerous pieces of legislation including the *Public Utilities Act*,[8] the *Gas Utilities Act*,[9] the *Electric Utilities Act*,[10] the *Pipeline Act*,[11] the *Hydro and Electric Energy Act*, and the *Gas Distribution Act*.[12]

[15] The Alberta government has implemented this specialized and integrated legislative framework to ensure that the Commission is able to provide oversight of the transmission, distribution and some aspects of the retail sale of natural gas and electricity within Alberta. That oversight includes the Commission's familiar regulatory rate-setting function *vis à vis* certain investor-owned natural gas, electric and water utilities and certain municipally owned electric utilities only.[13] Rate-setting involves ensuring that customers have access to the utility at a fair price while also providing utility companies with the opportunity to earn a fair return for their

[6] Prior to the creation of the EUB in 1995, this fell within the mandate of the ERCB: see *Hydro and Electric Energy Act*, RSA 1980, c H-13, s. 1(a). Today, these projects are initially proposed, in terms of their identified need, by the Alberta Electric System Operator established under the *Electric Utilities Act*.

[7] The Alberta Energy Regulator was established under s. 3, and the ERCB dissolved under s. 81, of *REDA*.

[8] RSA 2000, c P-45.

[9] RSA 2000, c G-5.

[10] SA 2003, c E-5.1.

[11] RSA 2000, c P-15.

[12] RSA 2000, c G-3.

[13] The Commission does not regulate Rural Electric Associations, municipally-owned utilities (with the exception of ENMAX in Calgary and EPCOR in Edmonton), natural gas co-ops, and most importantly, competitive retailers with whom customers sign a contract with a set price for the energy in question.

investors. However, the Commission's rate-setting authority is limited. In particular, the Commission does not regulate the price of natural gas which has been deregulated since 1985 nor the wholesale price of electricity which has been deregulated since 2001.

[16] Equally important, the Commission's role in regulatory rate-setting constitutes only part of the Commission's duties. Utility regulation today occurs against a backdrop of deregulation. It also involves changing economic models, including performance-based and incentive regulation designed to bolster competition and improve efficiency. The Commission's broad supervisory mandate extends to these issues too. In addition, the Commission must also deal with a myriad of technical, operational and infrastructure issues frequently involving difficult social, economic and environmental policy choices.[14] For example, companies that propose to construct electric generation, transmission or distribution facilities are required to secure site approval from the Commission. This often requires infrastructure and facility hearings. The Commission's jurisdiction extends as well to adjudicating cases brought to the Commission by the Market Surveillance Administrator (MSA). The MSA monitors the electricity and natural gas markets in Alberta to ensure they are operated in a fair, efficient and competitive manner.[15] It will be obvious therefore that, in exercising its statutory authority, the Commission is empowered to employ several different kinds of proceedings or hearings. Not all are regulatory rate-setting hearings.

[17] One final point. The Commission is a specialized body with a high level of expertise in a wide range of areas: ***Atco Gas and Pipelines Ltd v Alberta (Utilities Commission)***, 2014 ABCA 28 at para 26. These include: utility regulatory reform, competition policy, strategic planning and development, wholesale markets, service quality and compliance standards, performance-based and incentive regulation, capital structure of regulated utilities, debt and equity markets, utility assets dispositions, utility deregulation and, of course, rate-related regulation – along with the policy considerations involved in each. Of particular relevance to this appeal is the Commission's expertise in determining the amount and appropriateness of legal costs for applicants and interveners in the many kinds of proceedings before it.

III. Background Facts

A. Overview of Commission Decisions

[18] The ATCO Utilities challenge the Commission's decisions on legal costs in two separate proceedings. Proceeding No. 20, also known as the Utility Asset Disposition Proceeding (UAD Proceeding), is the subject of Appeal 1301-0069. Proceeding No. 2066, also known as the

[14] Section 17(1) of the *Act* explicitly requires the Commission to "give consideration to whether construction or operation of the proposed hydro development, power plant, transmission line or gas utility pipeline is in the public interest, having regard to the social and economic effects of the development, plant, line or pipeline and the effects of the development, plant, line or pipeline on the environment."

[15] The Commission is also charged with dealing with alleged contraventions of the rules of the Independent System Operator which operates under the name Alberta Electric System Operator.

Performance-Based Reform Proceeding (PBR Proceeding), is the subject of Appeal 1301-0070. In both Proceedings, the Commission determined that it had the authority to manage and assess the legal costs of all regulated utilities in Alberta (collectively the Alberta Utilities) in proceedings before it and to establish rules and guidelines for the recovery of such legal costs. With respect to this latter point, the Commission had, shortly after it was created, adopted Rule 022. This Rule, which dealt with the awarding of costs to applicants and interveners in proceedings before the Commission, also included a Scale of Costs. So too does the current form of Rule 022 adopted effective February 6, 2013 which was in force at the time that the Commission made both costs orders now under appeal.[16]

[19] In both Proceedings, the ATCO Utilities were made parties by the Commission and invited, but not compelled, to participate. And in both Proceedings, the Commission declined, in exercising its costs authority, to award the ATCO Utilities all their legal costs.

[20] In particular, in the UAD Proceeding, the Commission awarded legal costs in accordance with Rule 022 for the period subsequent to October 17, 2012 only. The Commission initiated this Proceeding to consider the implications of the Supreme Court of Canada's decision in ***ATCO Gas and Pipelines Ltd. v Alberta (Energy and Utilities Board)***, 2006 SCC 4, [2006] 1 SCR 140 [***Stores Block***]. The UAD Proceeding commenced on April 2, 2008 and was suspended on November 28, 2008 at the request of the ATCO Utilities. It did not resume until four years later on October 17, 2012. The Commission initially denied all legal costs to the Alberta Utilities, including ATCO Utilities. However, during a review initiated by the ATCO Utilities, the Commission agreed to award the Alberta Utilities a significant portion of their legal costs but only for the post-resumption period. A full chronology of events leading to this costs decision follows in Part B below.

[21] In the PBR Proceeding, the Commission awarded the ATCO Utilities their legal costs in accordance with Rule 022 plus a premium of 20% on top of the Scale of Costs. That Proceeding, again initiated by the Commission, involved an examination of performance-based regulation (PBR) as part of a broader initiative by the Commission to reform utility regulation in Alberta. A full chronology of events leading to this costs decision follows in Part C below.

[22] The ATCO Utilities assert that, as regulated public utilities, they, and other regulated utilities, enjoy a general "right" to recover from their ratepayers all their prudently incurred costs for utility operations. In their view, that includes all their legal costs for all proceedings before the Commission, the only limitation being that these costs must meet the "prudently incurred" standard.

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[16] Rule 022 was initially approved by the Commission on January 2, 2008, the day after the Commission came into effect. That form of Rule 022 was stated to have been "Formerly EUB Directive 31B and Rules of Practice". Rule 022 was later the subject of further consideration by the Commission and a revised Rule, approved September 30, 2008, was adopted effective October 1, 2008. It was then adopted in its current form effective February 6, 2013. The only change of substance between the current Rule 022 and the version it replaced relates to the documentation required for taxi claims.

[23] The issue on appeal – indeed, the *only* issue on appeal – is whether the Commission had the statutory authority to do what it did. As Conrad JA put it: "The relevant issue for this court is the Commission's finding that it did have the *statutory authority* to make cost related rules and award or deny costs incurred by all participants in proceedings before it, including utilities": 2013 ABCA 331 at para 13, emphasis added.

[24] It is appropriate to pause here to stress that this appeal is not about how the legal costs that the Commission awards to Alberta Utilities are actually recovered. This too is within the discretion of the Commission. Various approaches may be taken to that subject.[17] Nevertheless, in the end, one way or another, the ATCO Utilities will be entitled to recover from their ratepayers the legal costs awarded by the Commission.

B. Chronology of Events Relating to the UAD Proceeding

[25] On April 2, 2008, the Commission issued a Notice initiating the UAD Proceeding. The Notice set out the Commission's three principal objectives in doing so as follows (at Appeal Record Digest (ARD) 69, P2), all of which were directly linked to the implications of ***Stores Block***:

> (1) provide interested parties an opportunity to advance and defend their interpretation of ***Stores Block***;
>
> (2) provide interested parties an opportunity to identify and explore the potential implications of ***Stores Block*** to utility regulation in Alberta; and
>
> (3) develop a consistent, principled approach to applying the guidance provided by ***Stores Block***, while providing sufficient flexibility to address the specifics of each proceeding.

[26] In ***Stores Block***, a majority of the Supreme Court concluded that ATCO shareholders should receive the total gain from appreciation in the value of land ATCO sold in Calgary despite the fact that ATCO's original investment had formed part of the rate base on which gas rates had been calculated and paid by ratepayers since 1922.

[27] In doing so, the Supreme Court reversed the long-standing practice of the EUB and its predecessors under which such gains would be shared between utility company shareholders and ratepayers. The result was to overrule the EUB which had found, consistent with that past

[17] Under section 13.1 of Rule 022, where the Commission has awarded costs in a hearing or other proceeding, it shall issue a cost order setting out the amount of the award and to whom and by whom the payment must be made. Section 13.4 provides that the cost order may state whether "an applicant named in the order is authorized to record the costs in its hearing costs reserve account."

practice, that an amount equivalent to ATCO's profit on the land should be allocated one-third to the utility and two-thirds as a credit to the utility's cost base for the benefit of ratepayers. Since rate decisions are not made in a factual vacuum disconnected from reality, present or future, that past practice had no doubt informed the EUB's view of what were just and reasonable rates in individual cases. The EUB would have been well aware that what it might consider appropriate at the rate-making front end would be directly linked to what it might consider appropriate at the back end, namely the sharing, in some manner, by regulated utilities of the gains made on their disposition of assets in certain circumstances.

[28] Thus, perhaps not surprisingly, ***Stores Block*** led to many more issues – and problems – than the case itself answered. The Notice included as Appendix A a long list of issues (Issues List) (at ARD 69, P6-8), some obvious, some not so obvious, that the Commission considered it was duty bound to address as a result of ***Stores Block***. The Notice stated in part at ARD 69, P1-2:

> The Stores Block Decision may have various implications with respect to regulation of Alberta utilities. In particular, the guidance provided by the courts may require re-consideration of certain aspects of traditional regulatory approaches to the acquisition and disposition of utility assets and to the setting of just and reasonable rates. Parties have argued various interpretations of the Stores Block Decision in several recent proceedings before the EUB and in various ongoing proceedings before the Commission. The Commission would like to develop a comprehensive understanding of these potential implications through this Proceeding and then to apply that understanding in a consistent manner in future decisions.

[29] The obvious issues flowing from ***Stores Block*** included: who is responsible for losses arising from the disposition of utility assets; should the rules allocating gains and losses on sale of assets outside the ordinary course of business also apply to assets sold in the ordinary course of business; does the Commission have the jurisdiction to require regulatory approval prior to the disposition of an asset which is no longer used or required to be used to provide service in Alberta; and is the Commission entitled to consider the proceeds of disposition on sale of assets as "revenue" to the utility companies for the purpose of fixing just and reasonable rates? The Notice and the Issues List revealed the magnitude, and complexity, of the issues arising from ***Stores Block*** as the Commission attempted to deal with the significant fallout from this case.

[30] In its Notice, the Commission also advised that all Alberta Utilities "shall be considered as parties to this Proceeding whether or not they register and actively participate in the Proceeding": ARD 69, P3. Thus, the Alberta Utilities were entitled, but not required, to participate in the UAD Proceeding. By making all Alberta Utilities parties, the Commission obviated the need for each Alberta Utility to apply individually to be made a party to the UAD Proceeding. All were invited to make written submissions addressing the issues in the Issues

List. The Notice also informed the Alberta Utilities, which included the ATCO Utilities, that the Commission would decline to consider cost claims by parties and that all would be responsible for their own costs. As explained in the Notice at ARD 69, P3:

> Parties who participate shall not be entitled to submit cost claims to the Commission and no funding will be awarded by the Commission to participants. **Each party shall be responsible for its own costs.** The Commission considers this Proceeding to deal with generic issues which concern all stakeholders and that utility ratepayers should not be required to underwrite the costs of the participants through regulated rates. [Emphasis in original]

[31] On April 11, 2008, the ATCO Utilities sent a letter requesting that the Commission reconsider its decision that the utility companies that chose to participate in the hearings would be responsible for their own legal costs. They further suggested that written submissions in the UAD Proceeding be deferred pending a decision of this Court relating to ATCO Gas's Carbon storage facility (what became ***ATCO Gas and Pipelines Ltd. v Alberta (Energy and Utilities Board)***, 2008 ABCA 200 [***Carbon***], leave to appeal to SCC refused, (2008), 469 AR 396 (note) (December 4, 2008)). In ***Carbon***, this Court concluded, as argued by ATCO Gas, that an asset was not "used or required to be used" under s. 37 of the *Gas Utilities Act* unless it continued to be used in an operational sense. Thus, even though it continued to generate revenue which could be used for the benefit of ratepayers, it was no longer part of the rate base.

[32] On May 9, 2008, the Commission sent a letter to the ATCO Utilities denying their request for a deferral. Regarding costs, it confirmed its previous position as outlined in the Notice. However, the Commission indicated it would be prepared to revisit the issue following the completion of its then ongoing review of cost recovery under Rule 022.

[33] In August, 2008, parties to the UAD Proceeding filed written submissions on the issues outlined in the Notice. That presumably included the ATCO Utilities. Reply submissions were due October 27, 2008. Then, on September 30, 2008, the Commission advised that it had adopted a revised Rule 022 to come into force October 1, 2008.

[34] On October 21, 2008, the ATCO Utilities filed a motion requesting that the Commission suspend the UAD Proceeding. Grounds for the request included i) allegations of bias on the part of the Commission and ii) pending decisions of this Court in the "Harvest Hills" matter and the "Salt Cavern" matter.[18] Two days later, the Commission relieved parties from having to file Reply Submissions by October 27, 2008, as initially scheduled.

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[18] This Court granted leave on both appeals on November 12, 2008: see 2008 ABCA 381 and 2008 ABCA 382.

[35] On November 28, 2008, the Commission suspended the UAD Proceeding.[19] While rejecting any reasonable apprehension of bias, the Commission agreed to the suspension pending the outcome of the "Harvest Hills" and "Salt Cavern" appeals given the overlap of issues between these cases and the UAD Proceeding.

[36] "Harvest Hills" was decided on May 8, 2009 in ***ATCO Gas and Pipelines Ltd. v Alberta (Energy and Utilities Board)***, 2009 ABCA 171, leave to appeal to SCC refused, 33269 (January 28, 2010). There this Court concluded that the Commission could only attach a condition to the sale of an asset where there was a close connection between the sale of the asset and the immediate need to replace it. "Salt Cavern" was decided on June 30, 2009 in ***ATCO Gas and Pipelines Ltd. v Alberta (Utilities Commission)***, 2009 ABCA 246, leave to appeal to SCC refused, (2010), 487 AR 404 (note) (January 28, 2010). There this Court concluded that a utility's unilateral withdrawal of an asset from its rate base was not a "disposition" under s. 26 of the *Gas Utilities Act*, and therefore did not require prior approval from the Commission. In both cases, ***Stores Block*** figured prominently in this Court's decisions in favour of ATCO Gas and its shareholders.

[37] On September 17, 2010, the Commission initiated a separate proceeding, Proceeding No. 833, entitled Generic Cost of Capital. Then on December 3, 2010, ATCO Gas filed a 2011-2012 General Rate Application (Phase I), initiating Proceeding No. 969. A year later, on December 5, 2011, the Commission issued its General Rate Application Decision. That Decision addressed in part the issue of production abandonment, the Commission finding that costs associated with assets which no longer have an operational purpose should be removed from a utility's rate base and borne by utility shareholders. Three days later, on December 8, 2011, the Commission issued its Generic Cost of Capital Decision. That Decision addressed in part the issue of stranded assets, the Commission finding that risks associated therewith should be borne by utility shareholders rather than ratepayers.

[38] Within two months, applications were filed for review and variance of both Decisions. In particular, on February 3, 2012, ATCO Gas filed an application for review and variance of the General Rate Application Decision. And on February 6, 2012, the ATCO Utilities filed an application for review and variance of the Generic Cost of Capital Decision.

[39] On June 4, 2012, the Commission issued Decision 2012-154[20] reviewing its Generic Cost of Capital Decision. In reviewing this Decision as it related to stranded assets, the Commission concluded that this issue should be considered either as part of the UAD Proceeding or in a generic proceeding regarding asset disposition and stranded assets. A few days later, on June 8, 2012, the Commission issued Decision 2012-156[21] reviewing its General Rate Application Decision. It concluded that the issue of production abandonment should also be considered either

[19] Decision 2008-123.
[20] Proceeding No. 1697.
[21] Proceeding No. 1698.

as part of the UAD Proceeding or as part of a generic proceeding regarding asset disposition and stranded assets.

[40] On June 19, 2012, the ATCO Utilities sought clarification from the Commission on a number of points in Decisions 2012-154 (stranded assets) and 2012-156 (production abandonment). In so doing, they also advised they would be filing cost claims on the basis that they had satisfied the preliminary question under both Decisions. In accordance with s. 5.3 of Rule 022, applicants who satisfy the "preliminary question" – that is, who convince the Commission that a decision should be reviewed – are eligible to claim costs for all aspects of the review proceeding. Later that month, on June 28, 2012, the Commission agreed to hear the ATCO Utilities' cost claims after the completion of the review proceedings relating to these two Decisions.

[41] It was not until October 17, 2012 that the Commission recommenced the UAD Proceeding. It also confirmed at that time that the UAD Proceeding would be broadened to include both the issue of stranded assets and production abandonment, one of the options that the Commission had suggested in Decision 2012-154 and Decision 2012-156 respectively. The Commission again reiterated its initial position that each party would be responsible for their own legal costs of participating in the UAD Proceeding.

[42] Later on November 23, 2012, the ATCO Utilities and a number of other Alberta Utilities filed an application to review and vary the Commission's October 17, 2012 decision confirming that each party would be responsible for their own legal costs in the UAD Proceeding. On December 18, 2012, the Commission agreed to proceed with a review of its October 17, 2012 decision without the need for any further submissions on whether to do so.

[43] The Commission issued its costs decision in the UAD Proceeding on February 20, 2013. It is from this costs decision that the ATCO Utilities now appeal. The Commission affirmed its earlier decision not to award legal costs for the period prior to October 17, 2012. That was the period during which the UAD Proceeding was limited to the questions raised in the Notice about the implications of ***Stores Block***. However, the Commission varied its decision with respect to legal costs incurred after the UAD Proceeding recommenced on October 17, 2012. That was the date on which the stranded costs and production abandonment issues were added to the UAD Proceeding. The Commission allowed the ATCO Utilities and other Alberta Utilities their respective legal costs calculated in accordance with the Scale of Costs under Rule 022 from October 17, 2012 until December 31, 2012 (in the case of Alberta Utilities regulated according to performance-based regulation) or the close of the UAD Proceeding (in the case of all other utilities and interveners).

[44] On January 17, 2014, after the Commission had released its decision on the merits in the UAD Proceeding,[22] the Commission then issued its actual costs orders in the UAD Proceeding.[23] In accordance with its February 20, 2013 Decision (which is the subject of this appeal), the Commission awarded ATCO Electric Ltd. $87,061.55 of the $104,685.10 it had claimed and ATCO Gas $62,923.56 of the $75,299.36 it had claimed.

[45] In the result, the ATCO Utilities received a substantial portion of the legal costs they had claimed in the UAD Proceeding for the period October 17, 2012 and following. These legal costs were calculated by the Commission in accordance with the Commission's Scale of Costs under Rule 022. The *only* period for which the ATCO Utilities did not receive legal costs was from the inception of the UAD Proceeding on April 2, 2008 until it was suspended on November 28, 2008 at the request of the ATCO Utilities. On the record before this Court, the Commission held no hearings during that time period. The legal costs for the ATCO Utilities for that time frame appear to be related to written submissions filed prior to the date of suspension of the UAD Proceeding and matters incidental thereto.

[46] On August 20, 2014, this Court granted the ATCO Utilities and others leave to appeal on a number of questions relating to the Commission's decision on the merits in the UAD Proceeding: ***FortisAlberta Inc v Alberta (Utilities Commission)***, 2014 ABCA 264. That appeal remains to be heard.

C. Chronology of Events Relating to the PBR Proceeding

[47] On February 26, 2010, the Commission sent a letter to interested parties, including the ATCO Utilities, advising of a rate regulation initiative roundtable. Parties were invited to participate in a roundtable discussion to assist the Commission with its initiative to reform utility rate regulation in Alberta. The stated purposes for this initiative were twofold at ARD 70, P1:

> The first is to develop a regulatory framework that creates incentives for the regulated companies to improve their efficiency while ensuring that the gains from those improved efficiencies are shared with customers. The second purpose is to improve the efficiency of the regulatory framework and allow the Commission to focus more of its attention on both prices and quality of service important to customers.

[48] The Commission's initiative proceeded from the assumption, set out in the letter, that rate-base rate of return regulation "offers few incentives to improve efficiency, and produces incentives for regulated companies to maximize costs and inefficiently allocate resources:" ARD 70, P1. As the Commission went on to say at ARD 70, P2: "Traditional rate-base rate of return

[22] Decision 2013-417.
[23] Decision 2014-013.

regulation provides few opportunities to create meaningful positive economic incentives which would benefit both the companies and the customers." To overcome these perceived problems with natural monopolies, the Commission indicated in the letter that it intended to reform regulation for electric and natural gas distribution services by replacing rate of return regulation with PBR. Under PBR, rates are typically adjusted annually by a formula that recognizes expected inflation and achievable productivity improvements. In the letter, the Commission advised that it had scheduled PBR to be implemented commencing July 1, 2011.

[49] A roundtable was held in March 2010 during which various distribution companies each agreed to file a PBR proposal. It was also agreed that the Commission would initiate a short proceeding to establish common principles in order to guide and assess those PBR proposals. On May 14, 2010, the Commission sent a letter to interested parties setting out the process for developing the PBR principles. That led to a PBR workshop in May of that year followed in June by parties filing their submissions and reply submissions on the principles that should guide PBR.

[50] On July 15, 2010, the Commission issued Bulletin 2010-20 setting out the five principles it would use to examine specific PBR proposals. Later, on December 13, 2010, the Commission released Decision 2010-578 dealing with its costs orders in favour of those companies participating in the Commission's development of those PBR principles. ATCO Gas and ATCO Electric submitted a cost claim totalling $48,791.96. The Commission awarded this entire amount on the basis of its Scale of Costs. No one appealed this Decision.

[51] That same month, December of 2010, the Commission agreed to the requests of ATCO Gas and ATCO Electric to delay their PBR proposal deadline to March 31, 2011 and to delay the Commission's implementation of PBR itself to January 1, 2013. In April, 2011, the Commission sent a letter setting out a new proceeding schedule whereby PBR proposals were to be submitted by July 22, 2011. The ATCO Utilities and others filed PBR applications by that deadline.

[52] On July 26, 2011, the Commission sent out a Notice of the PBR Proceeding to all natural gas and electric distribution utilities regulated by the Commission advising that the ATCO Utilities and some of the other Alberta Utilities had separately applied to the Commission for approval of a multi-year PBR plan for their respective distribution utility.[24] The PBR Proceeding was designed to allow the Commission to hear these separate applications together.

[53] In February, 2012, the ATCO Utilities filed updated PBR applications. Oral hearings for the PBR Proceeding commenced in April 2012 and lasted until May 9, 2012. Parties to the PBR Proceeding, including the ATCO Utilities, filed written arguments with the Commission in June with reply arguments filed by July 13, 2012.

[24] This PBR Proceeding was also known as Proceeding No. 566.

[54] Later, on July 18, 2012, the ATCO Utilities and other Alberta Utilities sent a letter to the Commission advising that they intended to seek full recovery of their legal costs for participating in the PBR Proceeding. Those legal costs would be in excess of the Commission's Scale of Costs under Rule 022 given what the Alberta Utilities argued were the complexity and unique nature of the PBR Proceeding. On July 30, 2012, the Commission established Proceeding No. 2066 to consider cost claims related to the PBR Proceeding. In August, the ATCO Utilities submitted cost claims requesting full recovery of their legal costs in the PBR Proceeding.

[55] The Commission issued Decision 2012-237 on September 12, 2012 dealing with the merits of the PBR Proceeding. It set out the Commission's determinations about the form of PBR to be employed for electric and natural gas distribution companies in Alberta commencing January 1, 2013.

[56] Then, on February 20, 2013, the Commission issued Decision 2013-051, the second decision under appeal before this Court. The Commission awarded legal costs to the ATCO Utilities in accordance with Rule 022 plus an additional 20%. It rejected arguments that the ATCO Utilities were entitled to all their legal costs "prudently incurred" and that the Commission's Scale of Costs was in conflict with the relevant legislation. ATCO Electric was awarded $914,463.83 of the $1,300,461.44 it claimed, while ATCO Gas was awarded $691,499.23 of the $1,060,443.05 it claimed.

[57] Having clarified that these appeals are limited to whether the Commission had the authority to award legal costs to the ATCO Utilities on a basis other than full recovery of all legal costs that meet the prudence standard, I next turn to the degree of scrutiny that this issue attracts.

IV. Standard of Review

[58] Where a tribunal is interpreting its home statute or a statute closely connected to its function and with which it is particularly familiar, the standard of review is presumptively reasonableness: ***Canadian Artists' Representation v National Gallery of Canada***, 2014 SCC 42 at para 13 [***National Gallery***]; ***McLean v British Columbia (Securities Commission)***, 2013 SCC 67 at para 21, [2013] 3 SCR 895 [***McLean***]; ***Alberta (Information and Privacy Commissioner) v Alberta Teachers' Association***, 2011 SCC 61 at paras 34, 39, [2011] 3 SCR 654 [***ATA***]. Even if a question of law is involved, administrative decisions are not necessarily reviewed for correctness: ***Dunsmuir v New Brunswick***, 2008 SCC 9 at paras 55-56, [2008] 1 SCR 190 [***Dunsmuir***]; ***Carbon***, *supra* at para 16; ***Newfoundland and Labrador Hydro v Newfoundland and Labrador (Board of Commissioners of Public Utilities)***, 2012 NLCA 38 at para 85, 323 Nfld & PEIR 127.

[59] Exceptions capable of overcoming the reasonableness presumption include constitutional questions; issues central to the legal system not within the expertise of the tribunal; the drawing of jurisdictional lines between two competing specialized tribunals; and questions of true

jurisdiction: ***Canadian National Railway Co. v Canada (Attorney General)***, 2014 SCC 40 at para 55; ***Smith v Alliance Pipeline Ltd.***, 2011 SCC 7 at para 26, [2011] 1 SCR 160 [***Smith***].

[60] The presumption will also be overcome in the exceptional circumstance of an administrative tribunal and a court having concurrent jurisdiction to decide the issue in the first instance: ***Rogers Communications Inc v Society of Composers, Authors and Music Publishers of Canada***, 2012 SCC 35 at paras 10-20, [2012] 2 SCR 283 [***Rogers***]; ***Lethbridge Regional Police Service v Lethbridge Police Association***, 2013 ABCA 47 at para 28, 542 AR 252. There is no suggestion that the exception from ***Rogers*** applies here. It is the Commission which is charged with determining legal costs in the first instance. That remains so regardless of the possibility that a court may come to consider the matter before the Commission: see ***McLean***, *supra* at para 24; ***Sound v Fitness Industry Council of Canada***, 2014 FCA 48 at paras 45-51, 455 NR 87.

[61] Instead, the ATCO Utilities argue that the Commission's decisions on legal costs should be reviewed for correctness because they involve a question of "true jurisdiction". Indeed, this point is foundational to their entire case. In their view, the Commission had no jurisdiction to award legal costs on the basis it did. Instead, on their theory, the Commission *must*, in accordance with both the statutory regime in effect in Alberta and the regulatory compact, award the ATCO Utilities all their legal costs for all proceedings before the Commission. Thus, it follows that the Commission is required to treat the legal costs of the ATCO Utilities, if they satisfy the prudence standard, as prudently incurred costs recoverable from their ratepayers. In other words, according to the ATCO Utilities, the only discretion the Commission possesses is in determining the extent to which those legal costs have been "prudently" incurred. In their view, the Commission has no authority to limit legal costs of regulated utilities to the amounts in the Scale of Costs set by the Commission, much less to deny costs and the Commission's claimed authority to the contrary involves a question of true jurisdiction.

[62] Courts should be careful before quickly labelling issues as ones of "true" jurisdiction: ***Council of Canadians with Disabilities v VIA Rail Canada Inc.***, 2007 SCC 15 at para 89, [2007] 1 SCR 650. A statute may confer numerous powers on a tribunal and it is common to say that a tribunal has the "power" or "jurisdiction" to take a particular step or action. However, the use of the word "jurisdiction" in this context does not raise issues of true jurisdiction providing that the powers are exercised within the four corners of the enabling statute. As pointed out by Rothstein J in ***ATA***, *supra* at para 34:

> In one sense, anything a tribunal does that involves the interpretation of its home statute involves the determination of whether it has the authority or jurisdiction to do what is being challenged on judicial review. However, since *Dunsmuir*, this Court has departed from that definition of jurisdiction.

[63] The Supreme Court's revised definition of jurisdiction has substantially restricted the kinds of matters that fall into the true jurisdiction category – and understandably so. The Supreme Court has yet to identify a question of true jurisdiction post-***Dunsmuir***, Rothstein J going so far in ***ATA*** as to question whether the category should exist at all. Recently, the United States Supreme Court actually did away with the concept in ***City of Arlington, Texas v Federal Communications Commission***, 133 S Ct 1863 (2013). Moldaver J noted in ***McLean***, *supra* at para 25 the trend of counsel attempting, without success, to rely on exceptions like true jurisdiction. He essentially reiterated the point that cases involving "true jurisdictional" issues will be very limited.

[64] Questions of true jurisdiction are narrow in scope and typically involve what may be called boundary jurisdiction issues. One example is where there is a conflict between which of two tribunals has jurisdiction over a particular matter. Or where the question is whether the subject tribunal has the jurisdiction over an issue as opposed to the courts or the executive branch of government. Where a tribunal is interpreting its home or a related statute, the category of questions of true jurisdiction will be read particularly narrowly: ***National Gallery***, *supra* at para 13; ***ATA***, *supra* at para 34. To put it the way that the Manitoba Court of Appeal did in ***Manitoba v Russell Inns Ltd. et al.***, 2013 MBCA 46 at para 52, 361 DLR (4th) 581 [***Russell Inns***]:

> ... true jurisdiction is a very narrow concept. If the legislation (usually the home statute) gives the adjudicator the authority to decide or to act, the manner in which it makes that decision or exercises that authority is not a question of "true jurisdiction" for the purposes of determining the applicable standard of review.

[65] The Commission's decisions on legal costs do not involve questions of true jurisdiction. Its decision to award costs to the ATCO Utilities on a basis other than as prudently incurred costs did not require it to determine whether it was statutorily permitted "to decide a particular matter": ***Canada (Canadian Human Rights Commission) v Canada (Attorney General)***, 2011 SCC 53 at para 18, [2011] 3 SCR 471 [***Mowat***]. It is common ground that the Commission has the statutory authority to award legal costs for proceedings and hearings before it. The only issue is whether it is required to decide the quantum of legal costs using one standard (full recovery as prudently incurred costs) rather than another (what the Commission considers reasonable in the exercise of its discretion). This question does not go to true jurisdiction so as to mandate a correctness standard of review. Instead, what is at issue is the scope of the discretion conferred on the Commission by statute. This is plainly within the range of jurisdiction and not outside the boundary of jurisdiction.[25] A tribunal's power to award legal costs often involves the interpretation of its home statute and is thus typically reviewed for reasonableness: see, for

[25] This situation is analogous to that described in ***Reference re Broadcasting Regulatory Policy CRTC 2010-167 and Broadcasting Order CRTC 2010-168***, 2012 SCC 68 at paras 107-108, [2012] 3 SCR 489 where the Supreme Court made the point that the CRTC's broad mandate to set rates and licensing conditions "involve 'a polycentric exercise', necessitating a 'considerable scope' of jurisdiction".

example, ***Smith***, *supra* at paras 27-33; ***Russell Inns***, *supra* at paras 68-78; and ***Mowat***, *supra* at paras 25-27.

[66] Admittedly, in ***Stores Block***, the Supreme Court, by a narrow 4-3 split, did characterize as "jurisdictional" and review for correctness the issue of whether the Commission's predecessor, the EUB, had the power to allocate proceeds of the sale of a public utility's assets to ratepayers. However, three points must be made. First, ***Stores Block*** preceded the Supreme Court's reformulation of the test for judicial review in ***Dunsmuir*** and this Court must now view the characterization of issues through the ***Dunsmuir*** lens. Put simply, that was then, and this is now. Second, the narrowing of the concept of "true jurisdictional issues" post-***Dunsmuir*** has led to increased deference towards utility regulators even where the so-called "regulatory compact" may be implicated: see Dustin Kenall, "De-Regulating the Regulatory Compact: The Legacy of *Dunsmuir* and the "Jurisdictional" Question Doctrine" (2011) 24 Can J Admin L & Prac 115; ***Toronto Hydro-Electric System Limited v Ontario Energy Board***, 2010 ONCA 284, 99 OR (3d) 481, rev'g (2008), 93 OR (3d) 380 (SCJ), leave to appeal to SCC refused, (2010), 280 OAC 400 (note). Third, the question before this Court does not involve as in ***Stores Block*** an open-ended concept of "public interest" (though I hasten to add that I make no comment on the scope of the Commission's proper authority under this concept) but rather specific wording dealing with the awarding of costs.[26]

[67] Nor does this Court's decision in ***Shaw v Alberta (Utilities Commission)***, 2012 ABCA 378, 539 AR 315 [***Shaw***] support the position of the ATCO Utilities. ***Shaw*** concerned legislative changes to utilities regulation and their effect on the Commission's ability to consider the public interest as part of a needs assessment for transmission lines. This Court found that the question was one of true jurisdiction since it had to be determined whether, as a result of legislative amendment, the issue remained within the Commission's statutory mandate or had been transferred to the legislature or executive. That situation is clearly distinguishable from the present appeals, which, unlike ***Shaw***, do not involve the question of whether it is the Commission or some other body or branch of government that has the authority to consider a particular subject matter.

[68] In summary, the Commission made its legal costs decisions on the basis of its interpretation of the *Act*. As this is its home statute, reasonableness presumptively applies and the ATCO Utilities have been unsuccessful in establishing that the applicable standard of review should be correctness. Accordingly, the Commission's conclusion that it has the statutory authority to award legal costs in the exercise of its reasonable discretion separate and apart from prudently incurred costs recoverable under the *Act* is to be assessed for reasonableness.

[26] Further, after ***Stores Block***, and pre-***Dunsmuir***, courts found ways to distinguish what some viewed as an unnecessarily narrow interpretation of the EUB's authority: see ***Natural Resource Gas Ltd. v Ontario Energy Board*** (2006), 214 OAC 236 (CA).

[69]All this said, even if I am wrong and the standard of review that applied to the Commission's interpretation of the scope of its authority to award legal costs were correctness, that standard would be met in any event. I now turn to why the Commission's decision that it has the authority and right to determine the amount of legal costs, if any, awarded to regulated companies appearing in proceedings before it is not only reasonable in law, it is correct.[27]

V. Analysis

A. Legal Costs in Proceedings Before the Commission

[70] It is important to bear in mind the different categories of legal costs that utility companies might incur in various proceedings before the Commission. As is evident from these appeals, not all of those legal costs are those typically called regulatory costs, namely ones incurred in the course of rate-base rate of return hearings.

[71] The UAD Proceeding did not involve actual rate-setting for a specific utility. The primary focus in the UAD Proceeding was initially on the implications of ***Stores Block***. In dealing with the consequences of ***Stores Block***, the Commission was required to confront many different issues, the vast majority of which concerned the extent to which the shareholders of Alberta Utilities or Alberta ratepayers would benefit – or not – from certain issues and consequences flowing from ***Stores Block***. The UAD Proceeding was later expanded to include issues relating to stranded assets and abandonment of production assets owned by gas utilities, both of which are linked to deregulation of the utilities sector.

[72] The PBR Proceeding too did not involve traditional rate-base regulation. It was part of the overall reform of the utility sector consequential upon the Alberta government's deregulation initiative. Those reforms included the Commission's initiative to replace rate of return regulation with PBR. The intention was to devise incentives to encourage Alberta Utilities to become more efficient. The purpose of the PBR Proceeding was to allow the Commission to consider applications by the ATCO Utilities and other Alberta Utilities for approval of their multi-year PBR plans. Thus, while the PBR Proceeding was directed to rates generally, it was a fundamentally different proceeding than the traditional hearing involving rate-base rate of return regulation.

[73] The point from all this is that in proceedings before the Commission, legal costs will be incurred for a variety of reasons. Not all are related to rate of return regulation.

[27] This avoids any issue about whether there would be, in any event, only one reasonable interpretation about the scope of the Commission's authority with respect to the awarding of legal costs: see ***McLean***, *supra* at para 38.

B. Interpretive Approach

[74] The starting point for considering what the relevant Alberta legislation provides on the subject of legal costs in proceedings before the Commission is this. There is no requirement in law compelling the Alberta government to statutorily provide for any legal costs to be paid to any party appearing before any tribunal established by it. As a general principle, the scope of authority of a provincially-created tribunal, including its ability to award legal costs in proceedings before it, falls within the exclusive domain of the provincial government. Tribunals are not courts and thus court costs, as that term is commonly understood, are not a mandatory feature of proceedings before tribunals. For example, the default rule for those appearing before the Workers Compensation Board in Alberta is no costs for anyone. In fact, the Legislature might also provide that the regulated entities are responsible for part or all of the costs of the regulating tribunal.[28]

[75] The case law is clear that the *Act* must be read in its entire context, in its grammatical and ordinary sense and in harmony with the legislative scheme, its object and the intention of the legislature: ***Rizzo & Rizzo Shoes Ltd. (Re)***, [1998] 1 SCR 27 at para 21. When the Legislature has expressly addressed a matter, those words are to be taken as meaningful and not as window dressing: Ruth Sullivan, *Sullivan on the Construction of Statutes*, 5th ed (Markham: LexisNexis, 2008) [Sullivan] at 210 ("It is presumed that the legislature avoids superfluous or meaningless words, that it does not pointlessly repeat itself or speak in vain.")

[76] Further, since all words in a statute take their colour from their surroundings, a court is obliged to consider the total context of the provisions to be interpreted: see ***Stores Block***, *supra* at para 48; ***Chieu v Canada (Minister of Citizenship and Immigration)***, 2002 SCC 3 at para 34, [2002] 1 SCR 84; ***Bell ExpressVu Limited Partnership v Rex***, 2002 SCC 42 at para 27, [2002] 2 SCR 559 [***Bell ExpressVu***]; Sullivan, *supra* at 24-25. In this regard, one must also consider how the *Act* operates with other relevant legislation since the Commission is governed by multiple pieces of legislation: ***Shaw***, *supra* at para 32. This larger statutory scheme under which the Commission carries out its multi-faceted duties cannot be ignored. As Baroness Hale correctly observed in ***Stack v Dowden***, [2007] UKHL 17 at para 69: "In law, context is everything". Statutes dealing with the same subject matter should be interpreted in a manner that ensures harmony, coherence and consistency between them: ***Németh v Canada (Justice)***, 2010 SCC 56 at para 14, [2010] 3 SCR 281; Sullivan, *supra* at 224; ***Lévis (City) v Fraternité des policiers de Lévis Inc.***, 2007 SCC 14 at para 47, [2007] 1 SCR 591; ***Bell ExpressVu***, *supra* at para 27.

[77] The purpose of this interpretive exercise has been summed up this way. "[S]tatutory interpretation is the art of finding the legislative spirit embodied in enactments": ***Bristol-Myers Squibb Co. v Canada (Attorney General)***, 2005 SCC 26 at para 102, [2005] 1 SCR 533. Against

[28] Indeed, s. 70 of the *Act* allows the Commission to impose an "administrative fee" in order to pay for its own expenditures associated with carrying out its duties. It may impose this on an owner of a utility. Section 70(6) deems the amount thus paid a cost for the purposes of the *Public Utilities Act*. In addition, historically, the costs of the Alberta Energy Regulator, and its predecessor ERCB, have been paid in part by the companies being regulated: see ss. 28 and 29 of *REDA*.

this interpretive backdrop, I will now explain why I have concluded that the Commission's interpretation of its authority under the *Act* with respect to the issue of legal costs is reasonable.

C. Why the Commission's Interpretation of Its Authority Under the *Act* is Reasonable

[78] The ATCO Utilities contend that the *Act* does not grant the Commission any authority to award legal costs according to its own guidelines. Instead, they maintain that as regulated utilities, they have a *right* to full recovery of all their prudently incurred costs and this includes their legal costs. In their view, the source of that right can be found in the relevant legislation and in the regulatory compact. On their theory, Alberta ratepayers would be responsible every day in every way for every legal cost that the Alberta Utilities incur in proceedings before the Commission (subject only to their being "prudently incurred"). This assertion, all-encompassing in its sweep, would effectively strip the Commission of any authority to require a regulated utility to bear its own legal costs or even to limit those legal costs in accordance with the Scale of Costs adopted by the Commission or otherwise.

[79] The Commission concluded that the *Act* conferred on the Commission the authority to decide whether, and to whom, to award legal costs and the amount of those legal costs. That conclusion is entirely reasonable. I offer six reasons why this is so. Indeed, I am bound to say that this conclusion is correct.

1. The *Act* Grants the Commission Discretionary Authority Over Costs

[80] First, the textual wording of the relevant legislation confers on the Commission the authority and discretion with respect to the awarding of costs. Tribunals obtain their jurisdiction from express statutory grants and by application of the doctrine of jurisdiction by necessary implication: ***Stores Block***, *supra* at para 38; ***Bell Canada v Canada (Canadian Radio-Television and Telecommunications Commission)***, [1989] 1 SCR 1722 at 1756. The Alberta government has historically chosen to confer a very broad grant of authority on the tribunal responsible for regulating the utility sector in this province. This was recognized by Binnie J in ***Stores Block***, *supra* at para 113 (in dissent but not on this point):

> While the statutory framework of utilities regulation varies from jurisdiction to jurisdiction, and practice in the United States must be read in light of the constitutional protection of property rights in that country, nevertheless Alberta's grant of authority to its Board is more generous than most.

[81] That is most assuredly so, perhaps in part because Alberta has been at the forefront of the development of the energy industry in this country; perhaps in part because Alberta recognized long ago that tribunals governing the utility sector required a broad jurisdiction to address the issues flowing from a large province with, at an earlier time, a limited population; and perhaps because the governments of this province have, throughout this province's history, understood

the strong public interest in tempering the consequences of natural monopolies through a tribunal with the robust powers required to accomplish this objective.

[82] The reality is this. For at least the last 91 years, the Legislature of this province has conferred on the Commission and its predecessors, including the PUB, the express statutory authority to determine whether to award participants in proceedings or hearings before it, their legal costs, if any, and, if so, the amount of those legal costs. This grant represents a deliberate legislative choice.

[83] Section 21, the current statutory provision on this subject, has been in the *Act* since the *Act* came into force January 1, 2008. Since then, the Commission has consistently relied on this section in deciding when and if costs should be awarded to participants in proceedings or hearings before it, and if so, the amount of those costs. Section 21(1) provides as follows:

> **Costs of Proceedings**
>
> 21(1) The Commission may order by whom and to whom its costs and any other costs of or incidental to any hearing or other proceeding of the Commission are to be paid.

[84] Costs, as that term is used in s. 21(1), includes legal costs. The Supreme Court has previously considered the question of what meaning ought to be ascribed to the term "costs" in an administrative tribunal's enabling legislation. As noted by LeDain J in ***Bell Canada v Consumers' Association of Canada***, [1986] 1 SCR 190 at 207: "I would agree that the word "costs" ... must carry the same general connotation as legal costs".

[85] The ATCO Utilities assert that s. 21 is only intended to authorize recovery of costs *by the Commission and interveners*. That is not so. Neither the wording of the statutory provisions nor the legislative history supports this interpretation. The section expressly states that the Commission "may order *by whom* and *to whom*" not only its costs but "*any other costs of or incidental to any hearing or other proceeding of the Commission are to be paid*" [Emphasis added]. This wording is clearly broad enough to include "applicants" as well as "interveners" in proceedings before the Commission.

[86] This discretion on the part of the Commission to decide when and if costs will be awarded, and to whom, also happens to be consistent with the legislative history relating to the Commission's predecessors for more than nine decades in this province. That this is so can be seen by examining statutory provisions under earlier legislation. Language similar to s. 21(1) allowing the EUB and before it, the PUB, to determine the amount of costs, and to whom and by whom they would be payable, can be traced back to 1923: see SA 1923, c 53, s. 49. The costs language from that era was essentially carried forward through RSA 1942, c 28, s. 50; RSA 1955, c 267, s. 51; SA 1960, c 85, s. 60; RSA 1970, c 302, s. 60; and RSA 1980, c P-37, s. 60. A

subsection was added in SA 1990, c 34, s. 3, creating a s. 60 that essentially mirrored what became s. 68 in the 2000 version of the *Public Utilities Board Act*.

[87] Prior to the *Act*, the EUB, the Commission's predecessor, had the express right to award costs in its discretion under s. 68 of the *Public Utilities Board Act*, RSA 2000, c P-45 as follows:[29]

> 68(1) The costs of and incidental to any proceeding before the Board, except as otherwise provided in this Act, are in the discretion of the Board, and may be fixed in any case at a sum certain or may be taxed.
>
> (2) The Board may order that its costs of or incidental to any proceeding before the Board are to be paid and by whom they are to be paid.
>
> (3) The Board may order by whom and to whom any costs are to [be] paid, and by whom they are to be taxed and allowed.
>
> (4) The Board may prescribe a scale under which costs are to be taxed.
>
> (5) The Board may, with the approval of the Lieutenant Governor in Council, prescribe the fees to be paid by local authorities or persons interested in the matters that come before the Board.

[88] When the *Act* was passed in 2007, Part I of the *Public Utilities Board Act*, which included s. 68, was repealed.[30] Instead, the Legislature included a costs provision in the *Act*, namely s. 21(1). What the Legislature has done in its more contemporary and plain language wording under the *Act* is to combine in this general s. 21(1) the various sections involving the authority to make costs orders under s. 68, in particular ss. 68(2) and (3).

[89] This brief historical review reveals that, for 91 years, the Legislature of this Province has seen fit to grant to every tribunal responsible for regulating the utility sector in Alberta – the PUB, later the EUB and now the Commission – the general discretion to award costs of proceedings before it. In wording familiar to this day, the 1923 legislation gave the PUB the authority to order "by whom and to whom any costs" were to be paid.[31] That necessarily includes a regulated utility participating in proceedings before that tribunal. The PUB had this authority

[29] While these powers were originally granted to the PUB, the EUB assumed the same powers when it was created in 1995: *EUB Act*, s. 10(1).

[30] At that time, the *Public Utilities Board Act* was renamed the *Public Utilities Act*: see SA 2007, c A-37.2, s. 82(25).

[31] See s. 49(2) of the *Public Utilities Act*, SA 1923, c 53.

from 1923 until 1960 under various provisions of the *Public Utilities Act* and from 1960 to 1995 under s. 60 of the *Public Utilities Board Act*. And the EUB had this authority to determine whether to award costs, if any, and by whom and to whom and how much under the *Public Utilities Board Act* (s. 60 from 1995 to 2000 and s. 68 from 2000 to 2007).

[90] When the Legislature repealed Part I of the *Public Utilities Board Act*, including s. 68, and replaced it with the *Act* and in particular s. 21, there is no indication that the Legislature intended to strip the Commission of its right to determine by whom and to whom costs would be payable in proceedings before the Commission. Indeed, previously, s. 68 constrained the general authority of the PUB since this section stated that the PUB had the power to award costs "except as otherwise provided in this Act". However, by contrast, under the *Act*, the Commission's discretionary power to award costs is not stated to be subject to – and is not subject to – any statutory exceptions. In particular, the Commission's general discretion is not statutorily restricted to assessing only the prudence of legal costs incurred by utilities in proceedings before the Commission.

[91] In adopting the present legislative framework, including the *Act*, the Legislature also explicitly granted the Commission, as with its predecessors, the power and right to make rules governing any matter within its jurisdiction, that is within its authority under the *Act*. Hence s. 76(1)(e) of the *Act* provides as follows:

> (1) The Commission may make rules governing any matter or person within its jurisdiction, including ...
>
> > (e) rules of practice governing the Commission's procedure and hearings ....

[92] Since the awarding of costs falls within the Commission's jurisdiction, that power includes the right to make rules relating to the costs payable by, and to, applicants and interveners in proceedings before the Commission. In accordance with this more general rule-making authority under the *Act*, the Commission has adopted Rule 022 dealing with costs. Despite the fact that Rule 022 is entitled "Rules on Intervener Costs in Utility Rate Proceedings", it is clear from its provisions that it is intended to apply, and does, not only to interveners but also to applicants in proceedings before it. Section 2(c) defines "costs order" as an order of the Commission awarding costs on a claim for costs to a "participant" under s. 21 of the *Act*. In turn, "participant" is defined in s. 2(d) as an *applicant or an intervener* in a hearing or proceeding for a rate application or related to a rate application.[32] Therefore, the Rule explicitly distinguishes between applicants, on the one hand, and interveners, on the other – and includes both.

[32] Section 1 of Rule 022 also states: "These rules apply to hearings or proceedings for rate applications of utilities under the jurisdiction of the Commission or related to rate applications". Regardless, the Commission is entitled, in exercising its general discretion to award costs, to use the Scale of Costs for all forms of proceedings or hearings before it.

[93] As noted, Rule 022 includes a Scale of Costs that has been adopted by the Commission. Under s. 3.3 of Rule 022, an "applicant" is eligible to claim costs. Section 9.1 of Rule 022 provides that an eligible participant may apply to the Commission for an award of costs incurred in a hearing or other proceeding by filing a costs claim. Under s. 9.2, an eligible participant may only claim costs in accordance with the Scale of Costs. Given the amounts specified in the Scale of Costs, a utility reimbursed in accordance with that Scale is essentially recovering the majority of its *solicitor-client costs*. Moreover, the Scale of Costs is flexible, not rigid, and contemplates the possibility of the Commission's adjusting the amounts it awards for legal costs – and that includes increasing those amounts – depending on the circumstances of the individual case and the eligible participant.

[94] The ATCO Utilities made much of the fact that the discussions in the Legislature about Bill 46 that resulted in the *Act* focussed on the funding of legal costs for interveners.[33] In their view, those discussions support their assertion that s. 21(1) was intended to deal only with the costs of interveners and the Commission. Indeed, they went so far as to argue that this section was added to ensure that the Commission could award costs for interveners, the implication being that the Commission's predecessors did not have this right. However, this is not consistent with the legislative history of utility regulation in Alberta.

[95] Prior to the passage of the *Act* in 2007, a broader class, interveners generally, had the right to seek funding for their legal costs for proceedings before the Commission.[34] A review of Hansard reveals that the Alberta government decided that only "local interveners", and not other interveners, should have the right to recover their legal costs when challenging the location of certain facilities. Thus, in the *Act*, the Legislature restricted funding in certain cases to what it defined as "local interveners".[35] In doing so, it also included a separate section, s. 22(2), dealing with costs payable to local interveners, including the Commission's right to make rules for payment of costs to them.[36] The *Act* also gave the Commission the right under s. 21(2) to make rules respecting the payment of costs to interveners other than local interveners.[37] The point to be

[33] Alberta, Legislative Assembly, *Hansard*, 26th Leg, 3rd Sess (15 November 2007) at 2005 (Mr. Knight).

[34] It has been noted that "[t]he Alberta Public Utilities Board was the first regulatory tribunal in Canada to award intervenors' costs": Janet Keeping, "Intervenors' Costs" (1990) 3 Can J Admin L & Prac 81 at 86.

[35] For purposes of s. 22, "'local intervener' means a person or group or association of persons who, in the opinion of the Commission, (a) has an interest in, and (b) is in actual occupation of or is entitled to occupy land that is or may be directly and adversely affected by a decision or order of the Commission in or as a result of a hearing or other proceeding of the Commission on an application to construct or operate a hydro development, power plant or transmission line under the *Hydro and Electric Energy Act* or a gas utility pipeline under the *Gas Utilities Act*, but unless otherwise authorized by the Commission does not include a person or group or association of persons whose business interest may include a hydro development, power plant or transmission line or a gas utility pipeline."

[36] Section 22(2) provides: "The Commission may make rules respecting the payment of costs to a local intervener for participation in any hearing or other proceeding of the Commission."

[37] Thus, s. 21(2) provides: "The Commission may make rules respecting the payment of costs to an intervener other than a local intervener referred to in section 22."

taken from all this is that nothing in either s. 21(2) or s. 22 derogates from the Commission's general discretion under s. 21(1) to issue costs orders relating to those appearing in proceedings before it, whether as applicants or interveners.

[96] Further, it should be noted that s. 11 of the *Act* confers on the Commission the powers of a superior court judge regarding the payment of costs:

> In addition to any other powers conferred or imposed by this Act or any other enactment, the Commission has, in regard to the attendance and examination of witnesses, the production and inspection of records or other documents, the enforcement of its orders, *the payment of costs* and all other matters necessary or proper for the due exercise of its jurisdiction or otherwise for carrying any of its powers into effect, all the powers, rights, privileges and immunities that are vested in a judge of the Court of Queen's Bench. [Emphasis added]

[97] Since this section extends to the Commission the same powers respecting the payment of costs that a superior court judge enjoys, that includes the awarding of costs. Section 11 therefore reinforces the Commission's right to determine when and to whom legal costs will be awarded in connection with the proceedings before it. However, s. 11 does not constrain the right on the part of the Commission to make its own rules relating to the *amount* of those costs and the considerations it may take into account in awarding them. This it has done in Rule 022.

[98] Further, a general discretion to award costs necessarily implies the discretion to decline to award costs: ***Northern Engineering & Dev. Co. v Philip***, [1930] 3 DLR 387, [1930] 1 WWR 615 (Man CA).[38] Indeed, this Court has held that it will not interfere simply because a Board exercises its discretion to deny costs for participating in a hearing, even in the absence of reasons: ***Wood Buffalo (Regional Municipality) v Alberta (Energy and Utilities Board)***, 2007 ABCA 192 at paras 9-10, 417 AR 222.

[99] While not directly in issue here, the Commission's discretion in awarding costs must be exercised in a principled fashion: ***Green, Michaels and Associates Ltd., City of Edmonton and Consumers' Association of Canada (Alberta Branch) v Public Utilities Board*** (1979), 13 AR 574 at paras 20-23, 94 DLR (3d) 641 (Alta SC(AD)) [***Green***]; ***Consumers' Association of Canada (Alberta) and Edmonton v Public Utilities Board*** (1985), 58 AR 72 at paras 18-28 (CA). However, where, as here, a statute grants a tribunal discretion and the ability to pass regulations (which includes guidelines) regarding the exercise of that discretion, "the tribunal is able to mold the exercise of the discretion in any reasonable way that is not inconsistent with the statute": ***Kelly v Alberta (Energy Resources Conservation Board)***, 2012 ABCA 19 at para 17,

[38] This very point was made by the Canadian Association of Petroleum Producers in opposing the claim by the ATCO Utilities for full recovery of their legal costs based on the prudently incurred standard. See para 21 of ARD 69 at F4.

519 AR 284. In this regard, as this Court's decision in ***Green*** itself illustrates, a utility board can exercise its discretion on legal costs in a principled manner by following its own guidelines. Moreover, guidelines passed by tribunals under their grant of jurisdiction to do so are themselves entitled to deference when they are within that grant framework: see ***Parada v Alberta (Appeals Commission for Alberta Workers' Compensation)***, 2011 ABCA 44 at paras 26-28, 499 AR 169; and ***Martin v Alberta (Workers' Compensation Board)***, 2014 SCC 25 at para 11, [2014] 1 SCR 546 [***Martin***].[39]

[100] The exercise of discretion can include such considerations as convenience, utility, and savings of expense: ***Green***, *supra* at para 21. That is exactly what the Commission, as the successor to the PUB, provided for here. It set out in s. 11.2 of Rule 022 an extensive list of the considerations that the Commission may take into account in making a costs award. That list, borne out of its own experience and that of its predecessors, the EUB and the PUB, includes considering whether the party claiming costs:

> (a) asked questions on cross-examination that were unduly repetitive of questions previously asked by another participant and answered by the relevant witness;
>
> (b) made reasonable efforts to ensure that its evidence was not unduly repetitive of evidence presented by another participant;
>
> (c) made reasonable efforts to cooperate with other parties to reduce the duplication of evidence and questions or to combine its submission with that of similarly interested participants;
>
> (d) presented in oral evidence significant new evidence that was available to it at the time it filed documentary evidence but was not filed at that time;
>
> (e) failed to comply with a direction of the Commission, including a direction on the filing of evidence;
>
> (f) submitted evidence and argument on issues that was not relevant;
>
> (g) needed legal or technical assistance to take part in the hearing or other proceeding;

[39] In *Martin*, *supra*, the Supreme Court confirmed that the proper standard of review for such regulations was reasonableness. In so doing, it applied that standard not merely to the application of the policy guideline adopted by the Workers' Compensation Board, but directly to the policy itself: see paras 47-54.

> (h) engaged in conduct that unnecessarily lengthened the duration of the hearing or other proceeding or resulted in unnecessary costs to the applicant or other participants;
>
> (i) failed to comply with these rules or Rule 001, *Rules of Practice*.

[101] In summary, the Alberta Legislature chose to confer on the Commission, as with its predecessors, a discretionary costs authority coupled with the right on the part of the Commission to create costs guidelines with respect to its proceedings. The Commission passed costs guidelines, namely Rule 022, which it then applied in deciding the amount of the legal costs to be awarded to the ATCO Utilities. Thus, in concluding that it possessed the statutory authority to make the costs orders that it did, the Commission acted reasonably.[40]

2. The Legislation Does Not Provide for Full Recovery of Legal Costs by Alberta Utilities

[102] There is nothing in the relevant legislation that entitles Alberta Utilities to full recovery of their legal costs. The ATCO Utilities point to s. 4(3) of the *Roles, Relationships and Responsibilities Regulation*, AR 186/2003 under the *Gas Utilities Act*, RSA 2000, c G-5, and ss. 102 and 122 of the *Electric Utilities Act*, RSA 2003, c E-5.1 in support of their claim for full recovery of their legal costs as part of their prudent costs.

[103] Section 4(3) of the *Roles, Relationships and Responsibilities Regulation* provides:

> A gas distributor is entitled to recover in its tariffs the prudent costs as determined by the Commission that are incurred by the gas distributor to meet the requirements of subsection (1).

Section 4(1) in turn lists a number of functions of a gas distributor in respect of which it is statutorily entitled to recover its prudent costs. However, legal costs for attending proceedings before the Commission is not one of them. All of the listed functions relate to costs associated with certain functions inherent in gas distribution. Hence, there is nothing in s. 4(1) that would entitle a gas distributor, in this case, ATCO Gas, to its prudent legal costs for participating in hearings or proceedings before the Commission.

[104] With respect to the *Electric Utilities Act*, s. 102(1) requires each owner of an electric distribution system to prepare a distribution tariff for the purpose of recovering the prudent costs "of providing electric distribution service by means of the owner's electric distribution system." Again, s. 102 does not confer on the owner a "right" to recover its legal costs as "prudent costs".

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[40] This being so, the Commission is entitled to deference in respect of its discretionary costs orders: ***Lavesta Area Group v Alberta (Energy and Utilities Board)***, 2009 ABCA 155 at para 22; see also ***Newfoundland & Labrador Hydro v Newfoundland & Labrador Federation of Municipalities*** (1979), 24 Nfld & PEIR 317 at paras 5-7, 24-25 (CA); ***Facility Association v Board of Commissioners of Public Utilities (Nfld and Lab) et al.***, 2004 NLSCTD 81 at paras 56-63, 237 Nfld & PEIR 285, aff'd 2005 NLCA 56 at para 4, 250 Nfld & PEIR 1.

Section 122 is the general section imposing on the Commission the principle it must follow when considering a tariff application. Section 122(1) provides that when considering a tariff application, the Commission must have regard for the principle that a tariff approved by it must provide the owner of an electric utility with a reasonable opportunity to recover a number of costs. It lists several costs from s. 122(1)(a) to (h) inclusive. None relate to legal costs of proceedings before the Commission. All are specific to other matters. The only general one is s. 122(1)(h), which provides:

> any other prudent costs and expenses that the Commission considers appropriate, including a fair allocation of the owner's costs and expenses that relate to any or all of the owner's electric utilities

[105] The logic of this subsection read together with the other subsections in s. 122 is manifest. It is intended to relate to other costs and expenses of providing *services* to ratepayers in addition to those mentioned in subsections (a) to (g) inclusive, not the legal costs of attending regulatory proceedings before the Commission, much less other "generic" proceedings. Had the Alberta Legislature wished to include legal costs as part of those prudently incurred costs to which utilities were entitled, it could have explicitly done so. It did not. It expressly left these in the discretion of the Commission. The existence of that express discretionary authority over costs also contradicts the assertion that legal costs are included within the scope of the general wording in s. 122(1)(h).

3. Policy Reasons Support the Discretion in Favour of the Commission

[106] Policy reasons also strongly favour the Legislature's decision to grant the Commission a general discretion with respect to the awarding of legal costs. Without the ability to regulate legal costs as the Commission considers appropriate, the Commission would be unduly restricted in its ability to govern its proceedings. Without this control, there would be no effective incentive on any party in proceedings before the Commission to minimize their legal costs. If all legal costs (I am here referring to those that meet the prudence standard) can be paid from the ratepayer purse, where is the incentive for a utility to hold legal costs in check and minimize challenges and objections or the scope of the subject proceedings? And if all legal costs are recoverable, where is the incentive not to seek review and variance of every Commission decision adverse to the utility? Finally, if all legal costs of a utility company are recoverable as prudent costs no matter the nature of the proceedings before the Commission, where is the balance between the utility company and the ratepayers?

4. The Regulatory Compact Cannot Trump the Statutory Scheme Adopted by the Legislature

[107] Whatever the scope of the so-called regulatory compact at common law, it cannot trump statutory provisions that define the terms of the regulatory compact in Alberta. The origins of the

regulatory compact can be traced back to American law.[41] It arose out of a belief that efficient competition was not practical for certain utilities. The underlying concept was that the cost of providing parallel distribution systems where infrastructure costs were high was simply not practicable. To encourage utility companies to spend the relatively high capital costs required to put a functioning utility system in place, legislatures granted utilities exclusive rights to serve customers in a given service area. Since this meant a monopoly in favour of the utility, the utility was also required to serve all customers in that area. The obligation to serve is therefore the corollary of the utility having been granted a monopoly.[42]

[108] The common law in Canada imposed a duty to serve on suppliers of gas and electricity from an early stage in our history: see ***Canada (Attorney General) v Toronto (City of)*** (1893), 23 SCR 514.[43] The courts were the ones that initially intervened to prevent abuses of monopoly powers. However, it was not long before various legislatures transferred to regulatory tribunals the responsibility to regulate public utilities. As noted, in Alberta, the earliest body invested with broad regulatory powers over gas and electric utilities was the PUB, beginning in 1915.

[109] It is sometimes said that the regulatory compact means that a utility has a "right" to recover its costs because of its "obligation to serve". However, this is an overstatement of the concept. Even at common law, the regulatory compact did not guarantee full recovery of all costs. It offered an "opportunity" both to earn a reasonable return on its prudent investment – its capital costs – and to recover its prudently incurred expenses – its operating costs. As Kenneth Rose stated in *An Economic and Legal Perspective on Electric Utility Transition Costs* (Columbus, Ohio: National Regulatory Research Institute, 1996) at 43:

> In return for undertaking these obligations [including the obligation to serve, to provide safe and reliable service and not to engage in undue price discrimination], the utility is granted an *opportunity* to earn a reasonable return on its prudent investment and to recover its prudently-incurred expenses. *It does not bestow on the utility a legal right to recover all incurred costs or a return on its investments...* There simply is no absolute guarantee that a reasonable return will be earned or that reasonable costs will be recovered.[Emphasis added]

[110] Further, the specific terms of the regulatory compact were never cast in stone but subject always to whatever limitations might be imposed by the relevant legislature. Put into the context

[41] See the decision of the United States Supreme Court in ***Munn v Illinois***, 94 US 113 (1876).

[42] To put it as Michael H. Ryan did in "Telecommunications Carriers and the 'Duty to Serve'" (2012) 57:3 McGill LJ 519 [Ryan] at 537: "Public-utility services have historically been provided on a monopoly (or near-monopoly) basis and it seems fair to say that the existence of a monopoly has been one of the defining features of the public utility."

[43] For an excellent discussion tracing the origins of the common law duty to serve, see Ryan, *supra* at 522-534.

of this case, the scope of the regulatory compact falls within the jurisdiction of the Alberta government. In keeping with its right to determine the scope and terms of the regulatory compact, the Legislature has adopted legislation designed to govern its operation in Alberta. That legislation under both the *Electric Utilities Act* and the *Gas Utilities Act* grants regulated utility companies the *opportunity* to recover prudent costs as expressly provided for in the governing legislation.[44] But as noted, neither piece of legislation provides for legal costs to be characterized and treated as prudent costs. To the contrary. As noted, the *Act* expressly confers on the Commission the discretion to decide in an individual case whether the legal costs of proceedings before it will be payable to a regulated utility and it also grants the Commission the right to adopt rules in respect of payment of those costs.

[111] In other words, even if the regulatory compact at common law "guaranteed" recovery of all prudent legal costs, any such claimed "right" to legal costs under the common law must give way to a contrary legislative intent.[45] That contrary legislative intent is manifest in the express provisions adopted by the Alberta Legislature with respect to legal costs. To repeat, the regulatory body governing the utilities sector in this province has had the general discretion to determine to whom and by whom legal costs would be payable in connection with proceedings before that body for almost a century.

[112] In summary, the regulatory compact is governed by the statutory framework under which it operates in Alberta. The Alberta government has the right to decide the shape and terms of that framework unless the legislation it adopts is unconstitutional or void for uncertainty. No such challenge to the legislation has been made in these cases.

5. The Disputed Legal Costs Are Not Legal Costs Incurred in Rate-Setting Hearings

[113] In any event, the legal costs in dispute here do not fall within the scope of regulatory costs incurred in rate-setting hearings. In recent years, the so-called regulatory compact, involving as it does natural monopolies, has increasingly been challenged as the theory of the regulated monopoly has collided with the reality of the inefficiencies embedded in its operation. That has led to reforms of the utility sector in Alberta. In turn, that has resulted in proceedings by the Commission, sometimes characterized as generic proceedings, to deal with the consequences of deregulation and related court decisions. Proceedings in these categories do not involve rate-setting in the historical sense of that term.

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[44] Section 122 of the *Electric Utilities Act*, for example, ensures that a utility has a reasonable opportunity to recover certain kinds of prudent costs and expenses only: Decision 2005-053 at p. 5. A reasonable opportunity does not guarantee recovery: Decision 2004-012 at p. 8.

[45] In the United States, where a state chooses to allow for regulatory costs, or what is often called "rate case expenses", an express provision permitting recovery of those costs may be included in the governing legislation. For example, see ***Oncor Electric Delivery Company v Public Utility Commission of Texas***, 406 SW 3d 253 at 263 (Tex App Ct 2013): "The utility's operating expenses may include reasonable rate case expenses", citing s. 36.061(b)(2) of the *Texas Utility Code*, which provides "reasonable costs of participating in a proceeding" (see ***Texas Industrial Energy Consumers v Centerpoint Energy Houston Electric***, 324 SW 3d 95 at 106 (Tex Sup Ct 2010)).

[114] Rate-setting hearings require the Commission to determine whether the rates claimed are "just and reasonable". In discharging this obligation, the Commission must act in the public interest by considering both the customers' right to fair and reasonable rates and the utilities' reasonable *opportunity* to its prudent costs: ***ATCO Electric Limited v Alberta (Energy and Utilities Board)***, 2004 ABCA 215 at paras 131-132, 152, 361 AR 1. However, neither the UAD Proceeding nor the PBR Proceeding dealt with rate-setting in the traditional sense.

[115] In the UAD Proceeding, the period for which ATCO received no legal costs at all related to the time frame when the issues before the Commission were limited to the implications of ***Stores Block***. That was from April 2008 to November 2008. Those issues were not related to providing actual utility services to Alberta consumers. This part of the UAD Proceeding was directed to the ripple effects of ***Stores Block***. ATCO Gas won that case. Having done so, the ATCO Utilities were no doubt very much interested in ensuring that the new issues of concern to the Commission not be decided in a way that was disadvantageous to the ATCO Utilities and their shareholders.

[116] This is perfectly understandable. As Bastarache J correctly pointed out in ***Stores Block***, *supra* at para 78, private companies are run for profit. Indeed, that is what allows them to raise the capital they require for capital intensive utility projects. The Alberta Utilities are not running charities for the benefit of their ratepayers. But equally, Alberta ratepayers are not running charities for the benefit of the Alberta Utilities. The Commission concluded, in essence, that it was not fair to download onto Alberta consumers the legal costs of the Alberta Utilities, including the ATCO Utilities, in making submissions before the Commission as to how the fallout from ***Stores Block*** might, or might not, further benefit them or their shareholders. The Commission gave the ATCO Utilities the gift of standing in the UAD Proceeding. It did not promise that this gift would include allowing them to recover their legal costs from their ratepayers when the issues before the Commission involved the implications of ***Stores Block***. In fact, the Commission initially made it clear – and repeatedly – that none of the parties to the UAD Proceeding would be entitled to claim costs (which would in turn be recoverable from ratepayers).

[117] Moreover, as already noted, for the time period from the resumption of the UAD Proceeding on October 17, 2012 and following, when the focus shifted to stranded assets and production abandonment, the Commission did award the ATCO Utilities a significant portion of their claimed legal costs. This was so despite the fact that these two issues related to the consequences of deregulation.

[118] As for the PBR Proceeding, the Commission awarded the ATCO Utilities their legal costs in accordance with the Scale of Costs plus an additional 20%. The focus of the PBR Proceeding was on the PBR plans proposed by certain Alberta Utilities to replace rate-based regulation. PBR is intended to reward utility companies and their shareholders if performance is improved. The theory behind this is that efficiencies arising therefrom will benefit ratepayers too. The PBR

plans proposed by the ATCO Utilities presumably benefitted them since they designed those plans themselves. In any event, in the result, the ATCO Utilities received the vast majority of their claimed legal costs.

6. Not Awarding or Limiting Legal Costs Does Not Improperly Reduce Rate of Return

[119] Finally, the Commission's decision on legal costs in an individual rate-setting case does not negatively impact on a utility's rate of return in an improper or unfair manner. It has been suggested that if the ATCO Utilities did not receive their prudently incurred legal costs, this would unfairly reduce their rate of return. But this is not so. The Commission is well aware of what its practices and rules are regarding the awarding of legal costs. When it sets a rate of return in an individual case, the Commission knows how it has treated, or will be treating, the issue of legal costs and whether they will be fully or partly recoverable as part of the rate base. Thus, this is necessarily taken into account in determining the rate of return. Put another way, if utilities had a "right" to full recovery of all their legal costs in every proceeding before the Commission, the rate of return set by the Commission in an individual case might well be lower.

D. Conclusion

[120] For all of these reasons, the Commission's interpretation of the relevant legislation is not only reasonable, it is correct. The Commission possesses the statutory authority to decide when, and in what circumstances, it will award legal costs to those appearing in proceedings before it, including regulated utilities, and the amount of those legal costs. In other words, the Commission possesses a separate authority over legal costs apart from its rate-setting authority. In accordance with its discretionary costs authority, the Commission is permitted to treat legal costs differently than other costs, that is operating and capital costs, of regulated utilities. Thus, there is no merit in the assertion that, in exercising that authority, the Commission acted in any kind of arbitrary manner. The Commission's costs discretion is not fettered by some imaginary right not included in the legislative regime in effect in this province. The Commission was authorized by law to make the costs orders that it did.

E. What is Not in Issue Before This Court

[121] It bears pointing out that the issue before this Court does not involve how much the ATCO Utilities choose to pay their legal counsel for proceedings before the Commission but rather who decides how much of those legal costs will be recoverable from Alberta ratepayers and on what basis. The ATCO Utilities contend that there is a difference between recovery of all legal costs (providing they meet the prudently incurred standard) and legal costs awarded in accordance with the exercise of the Commission's discretion. Nothing makes that point clearer than these appeals. The ATCO Utilities argue that the Commission had no authority to deny them their costs for the initial phase of the UAD Proceeding.

[122] The ATCO Utilities also go further. They assert that limiting their costs to the Scale of Costs in the UAD Proceedings (for the period for which they were awarded) means that they received less than what they would have been entitled to recover as prudent legal costs. Similarly, they contend that even a 20% premium in addition to the Scale of Costs in the PBR Proceeding is not enough to meet what they claim they would have been awarded had the Commission awarded them their legal costs under the prudence standard. In other words, the ATCO Utilities reject the proposition that if their prudent legal costs were recoverable in both Proceedings, the costs awarded in accordance with the Commission's exercise of its discretion under Rule 022 would suffice to meet this standard.

[123] However, the focus of these appeals has not been on this issue. Apart from the general claim by the ATCO Utilities that such a difference would exist, we received no argument on this point.[46] The focus was properly on the issue on which leave was granted – whether the Commission possessed a separate authority to award legal costs. No one delved into whether the Commission's awarding of costs in accordance with Rule 022 and its Scale of Costs would, in any event, satisfy the prudence standard. Given the conclusions I have reached, this issue does not arise. However, if I am wrong in determining that the Commission did not err in its interpretation of its statutory authority, it does not necessarily follow that the ATCO Utilities would be entitled to recover additional legal costs. This would simply lead to the next question, namely whether there is a match between prudent legal costs and costs awarded by the Commission under Rule 022 and its Scale of Costs.

[124] In addition, this Court did not receive argument on what limits, if any, would apply to the exercise of the Commission's discretionary costs authority. In particular, would the Commission be acting unreasonably if it denied to a regulated utility its legal costs incurred in rate of return hearings as compared to the type of proceedings in question here? And what other limitations, if any, apply to a costs award by the Commission? These issues would in turn lead to others not before this Court. What has been the past practice in traditional regulatory rate-setting hearings? Should it, or should it not, continue to govern? Who is ultimately responsible for all, or substantially all, of the legal costs in rate of return hearings? How are those costs recovered? Has a proper balance been struck between the regulated utility companies and ratepayers? Leave was not granted on any of these issues and I decline to consider them further.

VI. Disposition

[125] In summary, the Commission did not err in law or jurisdiction by denying or limiting recovery of the ATCO Utilities' claimed legal costs in either the UAD Proceeding or the PBR Proceeding and by treating those costs differently than other costs. This is not a "starting point"

[46] Nor did this Court receive any argument from the Office of the Consumer Advocate of Alberta on the appeal involving the UAD Proceeding.

from which to assess the reasonableness of the legal costs awards themselves. It in fact ends the matter. Accordingly, both appeals are dismissed.

Appeal heard on May 9, 2014

Reasons filed at Calgary, Alberta
this 2nd day of December, 2014

Fraser C.J.A.

Reasons for Judgment Reserved of The Honourable Mr. Justice Côté Concurring in the Result

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A. Introduction

[126] There are two related appeals heard together. I will discuss them one at a time.

B. Appeal #1301-0069-AC

[127] In this proceeding, initially the two ATCO companies in advance were denied any costs. Later on that decision was reversed, but not fully retroactively.

[128] For this appeal, I did considerable reading about the traditional model of rate regulation for public utilities. I noted certain Canadian law, including ***Green Michaels & Assoc v Edmonton (City)*** 13 AR 574 (CA 1979) (para. 30); ***Bell Canada v Consumers' Assn of Canada*** [1986] 1 SCR 190, 205-06, 65 NR 1 (para. 27); ***Re National Energy Board Act*** [1986] 3 FC 275, 69 NR 174 (CA) (para. 10); *Gas Utilities Act* RSA 2000 c. G-5 ss 36, 40; *Electric Utilities Act* 2003 c. E-5.1 ss 102 and 121-22. Reading them gives me grave misgivings about whether the respondent Commission's main argument is a satisfactory or sufficient model to deal with rate hearing expenses. That argument is that the matter is simply a question of statutory "discretion" over costs.

[129] However, I have read in draft form the judgment of the Chief Justice about this appeal 0069. She convinces me that the hearing now under appeal is not the typical or traditional rate hearing. In the hearings which are the subject of the present appeal, several things were or are true:

(a) The Commission commenced the hearings now under appeal, and during much of their life, the appellant companies were not acting as, or even acting mostly as, traditional regulated public utilities, because the topic was largely or entirely treatment of assets neither used for nor required or useful for, the regulated utility business.

(b) Toward the end of the process, one appellant was taken out of the traditional type of rate regulation, and placed by the respondent Commission under a new type of rates and billing giving an incentive ("performance based").

(c) Though the total nominal time for this set of hearings was long, much of the gross time between start and finish of the proceeding elapsed during a stay, and it appears likely that nothing was happening then, and so it is unlikely that legal expenses of any significant amount were incurred by any appellant company on this precise matter.

(d) The respondent Commission later reconsidered its earlier refusal to grant any costs at all for this hearing, and reversed its earlier denial of all costs, retroactive to the end of the stay, and continuing up to the point where any of the appellants' charges ceased to be regulated on the traditional basis. (That distinction about types of regulation was suggested by the utilities themselves.)

[130] The formal record filed by the Commission for this appeal has been carefully checked, and it does not contain any more definite or detailed information about whether any appellant company incurred any relevant legal expenses during the stay. The sort of detailed information found in the Record for the parallel appeal (# 0070) is not found here.

[131] In the event that the Record before us on this appeal is insufficient on the precise amounts submitted or what work was or was not done during the stay, that is not enough to upset the Chief Justice's factual conclusions about points a. to d. above. The respondent Commission appears from its ultimate Reasons to have been of like mind, and those four points are reasonable inferences. The Board is also entitled to use its expertise and take notice of information which it received informally. See ***Northwestern Utilities v Edmonton*** (1929), *infra*.

[132] Therefore, my concerns about the principles to be applied in reimbursing or not reimbursing the rate hearing expenses of a public utility subject to traditional rate setting, become moot or academic in the present appeal (#0069).

[133] So I find it unnecessary to reach any final conclusion about anything else. For example, about how to handle a utility company's hearing expenses in the more ordinary type of rate hearing for a traditionally-regulated public utility. Still less need I comment on any competing view of that topic, such as the respondent Commission's arguments on that topic. To do so might be counterproductive.

[134] In these rather unusual circumstances, the respondent Commission had to use its experience and expertise to craft a fair and reasonable solution to the appellants' request for indemnification of its hearing expenses. Bearing in mind points a. to d. above, I am of the view that the Commission did so properly and reasonably here. That entails no error of law, given these circumstances, and even if there were one, it could not have affected the result.

[135] Mr. Justice Martin's judgment on appeal #69 discusses interesting questions of principle. In an ordinary rate hearing, they would have to be decided. But I am reluctant to go further today than I do in this judgment, because it is only about the unusual Commission hearing in appeal #69. I prefer to leave those questions of principle for another day. That is why I merely concur in the result with the judgment of Chief Justice Fraser (in both appeals).

[136] I do agree with Mr. Justice Martin that the principles which he adopts would not bar use of a tariff of legal fees like that under Rule 22.

[137] I would dismiss this appeal on the narrow ground expressed above.

C. Appeal #1301-0070-AC

[138] Even if one does not adopt the model of "costs" advocated by the Commission in appeal #0069, there is no reason to think that the respondent Commission is obliged to let anyone recover any unreasonable amount or degree of expenses incurred. No counsel before us suggested that the Commission should do that. It is doubtful that any such suggestion could be made, as the Commission's R 022, s 11 expressly adopts a test of reasonableness. So does case law and Commission practice: see Phillips, Regulation of Public Utilities 245 ff (2d ed 1988); Troxel, Economics of Public Utilities 237 ff (1947).

[139] In my view, that test of reasonableness includes whether

- the work was done at all;
- the work done was excessive;
- the people chosen to do the work were too expensive (e.g. too senior);
- too many people were put to work; or
- the charges of those working (e.g. hourly rates) were too high.

That is implied in the nature of rate regulation, and the legislation on regulating "costs" makes it explicit.

[140] One of the obvious purposes of the legislation about "costs" is to advance that same aim. Counsel's concessions that the respondent Commission can police the amounts charged for legal and other expenses of a regulatory hearing, are obviously well-founded in law.

[141] There is no relevant dispute about the standard of appellate review in this appeal #0070. The appellants and respondent disagree on the standard of review as to discrete questions of general law. But no such questions are in issue on this appeal. The respondent Commission found the appellants entitled to some degree of recovery of the expenses they incurred in the Commission hearings leading to this appeal #0070. No one contests that finding, and plainly it is correct.

[142] The only live issue in this appeal is how much the recovery should be. Nor is there any dispute among the parties that the test is reasonableness. The question of whether these particular

legal or similar bills were unreasonably high, is not a question of general law. Plainly (on an appeal) that would be tested on a deferential basis (i.e. reasonableness again). In any event, that is not the question on which leave was given, and is not a question of law or jurisdiction. Maybe the Court of Appeal would never hear such an appeal.

[143] Counsel for the appellants suggests that all expenses actually incurred by the utility companies are presumed to be correct and reasonable, and that the onus lies on the interveners to adduce evidence to the contrary. What is suggested is clearly only a duty on the interveners initially to lead **some** evidence, not a substantive onus of proof, which remains on the utility company: see ***Enbridge Gas Distribution v Ontario Energy Board*** (2006) 210 OAC 4 (CA) (para 11), leave den (2006) 361 NR 397 (SCC). See 9 *Wigmore on Evidence* §§ 2486-87 (Chadbourn rev 1981); *Phipson on Evidence* pp 160-161 (paras 6-02 to 6-03) (18th ed 2013).

[144] As the Commission is expected to use its expertise and experience, in my view it can act when it gets notice of what look to it like unusual or excessive expenses. It can at once require more proof from the utility, and need not wait passively for evidence from the consumers.

[145] The appellants cite ***ATCO Gas & Pipelines v Alberta Energy & Utilities Board***, 2005 ABCA 122, 367 AR 54 (para 66) (Tab 13). The Consumer Advocate's factum correctly points out that the context there and here are different, so it is doubtful that that decision has the wide scope which the appellants suggest. It has nothing to do with rate-hearing expenses, and is about what engineering methods the utility should adopt.

[146] It is difficult fully to reconcile the appellants' suggestion of an onus of proof on the consumers, with two well-established rules of law:

(a) The Commission has expertise and experience in this field, which it is expected to use, and that is an important reason why the Commission gets deference on appeal (or on judicial review). See ***Smith v Alliance Pipelines***, 2011 SCC 7, [2011] 1 SCR 160, 412 NR 66 (paras 26, 28); ***McLean v British Columbia (Securities Commission)***, 2013 SCC 67, [2013] 3 SCR 895, 452 NR 340 (para 21); *Jones & deVillars, Principles of Administrative Law* (5th ed, 2009), p 525, all citing ***Dunsmuir v New Brunswick***, 2008 SCC 9, [2008] 1 SCR 190, 372 NR 1 (para 54).

(b) The Commission is not limited to acting on evidence formally put before it by the utility company or an intervener; it can gather information spontaneously, by its own staff: ***Northwestern Utilities v Edmonton (City)*** [1929] SCR 186, [1929] 2 DLR 4, 8-9.

[147] Factual topics recur before the Commission from hearing to hearing, even between different utility companies. The Commission need not shut its eyes to that. If all other Alberta utility companies report paying about $x to buy a residential gas meter, and all treat it as having (say) an average life of 15 years, a utility company which estimated a purchase price of twice as

much per meter and a life half as long, should not be surprised if the Commission notices that and refuses to accept the company's numbers without strong evidence. The Commission would not thereby err.

[148] In any event, it is trite law that onus of proof normally only matters in the rare case where the evidence is evenly balanced. See for example ***ATCO Gas & Pipelines v Alberta Energy & Utilities Board***, 2005 ABCA 122, 367 AR 54, para 72.

[149] The traditional common-law presumption is that he who asserts must prove. Subject to the powers of the respondent Commission to use its own experience and expertise, or gather information for itself, that must be correct and logical. First, it is usually almost impossible to prove a negative.

[150] Second, almost always the utility company will know the facts and have the only records, and no intervener will have either. Forcing interveners to lengthen a rate hearing by purely speculative interrogatories or document production requests, and speculative live cross-examination, would be in no one's interest.

[151] The factum of the intervener Consumer Advocate states that in the hearing which led to appeal #0070, the Commission noted significant differences in the hourly rates claimed by the different participants for indemnity. The Commission therefore issued information requests to the appellant utilities and got argument on the point (paras 12-13). The appellant utilities filed a reply factum (April 10, 2014) to that Consumer Advocate's factum (and to the Commission's factum). But the appellants' reply did not dispute that assertion by the Advocate.

[152] In view of that procedural history, the question of who had the onus of proof of unreasonableness becomes virtually academic in this appeal.

[153] I agree with the Chief Justice that the respondent Commission had legislative power to enact a scale or tariff of fees. I believe that one reason for that was to avoid having to keep relitigating what level was reasonable.

[154] The respondent Commission also had the advantage in seeing the legal bills for all the parties and interveners in the hearing in question and in all related hearings. It knew how much work had been done, and how much of it was reasonable. The Commission could compare hourly rates of different law firms, and to a fair degree could assess the experience and ability of the counsel concerned.

[155] Merely looking at hours or total bills of different parties is not enough, as sometimes in a multi-party hearing one law firm or party does the lion's share of the work for one side, while its allies ride its coattails. But the Commission might well get some idea of who did more work too.

[156] Bills of non-ATCO counsel are not at all a benchmark to be used alone, but they do have some relevance, and reference to them would not disclose any *prima facie* case of the Commission's wandering outside a reasonable range of expenses.

[157] There does not seem to have been any dispute about the number of hours which the appellant companies' counsel worked, nor about whether that amount of work was reasonable. The appellants' counsel now states that the Commission found that the hours claimed were reasonable, citing paras 63-65 of its Reasons (Appeal Digest, p F16). Though the Commission's statement there is not express, that is the only possible interpretation of that passage. The Commission only adjusted the dollar amounts per hour (down to the Scale, then up by 20%). The hourly rates which it awarded were multiplied by the number of lawyer hours claimed. Similarly, the Commission's reasons paras 86 and 92 (in appeal #0070) show the same thing, both for lawyers' fees and consultants' fees. The respondent Commission's own factum (in appeal #0070) supports that conclusion (paras 6-8). So hours spent were reasonable and were accepted, and hourly rates were the only issue.

[158] I see no indication of error in principle in the respondent Commission's assessment of reasonable hearing expenses in this appeal #0070. Nor has anyone alleged that some specific passage in the Commission's reasons in appeal #0070 reveals error in principle, aside from the topics which I have discussed above.

[159] The Commission addressed itself to the right topics, and the numbers chosen by it are not manifest evidence of some lurking error of law. There is no ground to interfere, nor to send the matter back to the Commission to retax in the hope that some error might turn up.

[160] I would also dismiss appeal #0070.

[161] It would assist the court considerably if counsel would follow R 14.31(a) (formerly our Consolidated Practice Directions, Parts C.4 and D.1(b)), and give a citation from a law report (as well as neutral citation), for each case relied on.

Appeal heard on May 9, 2014

Reasons filed at Calgary, Alberta
this 2nd day of December, 2014

Côté J.A.

**Reasons for Judgment Reserved of The Honourable Mr. Justice Martin
Dissenting in Part**

[162] I have reviewed the draft judgments of my colleagues. They each dismiss both appeals, albeit for different reasons. While I concur in the result on Appeal No 1301-0070-AC, with respect, I take a different view of their disposition of the other, Appeal No 1301-0069-AC, which I would have allowed in part.

[163] I begin with the question on which leave was granted:

> Did the Commission err in law or jurisdiction by denying or limiting recovery of the appellants' claimed regulatory costs and by treating the costs of or incidental to any hearing or other proceeding of the Commission differently than other costs?

[164] The issue is whether the appellants should be able to recover from their customers, through their rates, prudently incurred legal costs arising from their participation in what has been described as two roundtable discussions. The Chief Justice's reasons provide a full factual background. For ease of reference I will repeat only those facts which I consider particularly material.

[165] As it relates to Appeal No 1301-0069-AC, also referred to as the Utilities Assets Disposition (UAD) appeal, the Commission was concerned that the Supreme Court's decision in ***ATCO Gas and Pipelines Ltd. v Alberta (Energy and Utilities Board)***, 2006 SCC 4, [2006] 1 SCR 140, **(*Stores Block*),** had serious implications on its regulation of Alberta utilities. Rather than address those matters on a piecemeal basis over an extended period, the Commission determined it would attempt to address them at one time, with input from the utilities. It was in this context that the utilities were "invited" to participate and given standing as parties. While it may be debated whether the utilities were compelled or required to participate, had they elected not to participate, it would have been at their peril; policies and procedures which directly affected them would have been developed without their input, perhaps to their detriment. So participate they did. At the end, they sought to recover the legal expenses they had incurred. As my colleagues have noted, the Commission initially denied recovery of all legal costs, but subsequently allowed legal costs for a significant part, the latter portion, of those proceedings.

[166] The material facts giving rise to Appeal 1301-0070-AC, referred to as the Performance Based Reform (PBR) proceedings, are similar. The Commission asked the appellants and others to attend another roundtable initiative aimed at developing a regulatory framework to create incentives to improve efficiencies of regulated companies, the benefits of which were to be

shared with their customers. At the conclusion of those proceedings, the Commission permitted the appellants to recover a portion of their legal expenses.

[167] The Chief Justice has undertaken a historical review of the Commission's authority to deny or limit recovery and has concluded that the Commission has such authority. That conclusion relies heavily on her interpretation of s 21(1) of the *Alberta Utilities Commission Act*, SA 2007, c A-37.2.

[168] The appellants submit that s 21 merely authorizes the Commission to recover its own costs and any incidental costs from others. I disagree. I prefer the Chief Justice's analysis and conclusion on this point, subject to the qualification discussed below.

[169] The appellants further submit that in any event s 21 does not express the Legislature's intention to displace the fundamental tenet, that a regulated utility is entitled to recover its prudently incurred expenditures. I agree with that submission.

[170] In my opinion, s 21 did not vest the Commission with the authority to arbitrarily deny or limit recovery of parties' legal expenses. Rather, it gave the Commission the authority or discretion to deny recovery of imprudent expenses, legal or otherwise, but no more.

[171] Allowing the recovery of prudently incurred costs has historically been the measure applied to all expenses and I see no justification to depart from that standard in situations of this kind, that is to say, in matters other than rate hearings. The concerns raised by the Chief Justice as to potential abuse or unfairness to the rate-payer may be addressed by the Commission allowing recovery of only prudently incurred expenses. Three examples will illustrate the point. If, in response to the Commission's invitation to participate, the utility assembled lawyers to address hypothetical matters of no assistance to the resolution of the issues at hand; or if counsel's claimed hourly rate was excessive, the Commission could (and should) limit recovery to that which was prudently incurred. Likewise, if counsel refused to co-operate with other counsel in addressing issues and that resulted in duplication of work, the Commission could reduce the expenses claimed to those that were prudent in the circumstances.

[172] But in my opinion, mindful of what the Chief Justice refers to as "the regulatory compact", the Commission may not, as it did here, ask parties to provide input and then arbitrarily decide that their cost of participation, including those that were prudent, would not be recoverable. If such unfettered authority did exist, one might reasonably contemplate a situation where the Commission could compel a party (a utility) to incur millions of dollars in costs at a protracted roundtable, and subsequently deny it the opportunity to recover even those expenditures prudently incurred in the process. As my colleagues have noted, the utility has no other recourse to recover such costs and the impact would be on its shareholders.

[173] In my opinion, the recovery of costs prudently incurred has been and remains an effective standard. It permits the Commission to deny costs associated with dubious applications and other imprudent expenditures. Fair application of that standard provides the necessary

incentive to regulated parties to be restrained in their claimed expenditures while at the same time giving them the security that prudent expenses will be recoverable.

[174] The scale of costs formulated by the Commission (Rule 22) is also implicated by the appellants' argument because it was used by the Commission to fix recoverable costs in one of the appeals. I understand that this scale provides guidance to interveners regarding the legal costs they may be entitled to recover. The appellants argue that recovery of their legal costs should not be fettered or guided by that scale. I disagree. Having developed this flexible scale as a reflection of what it considers to be reasonable legal tariffs associated with participation in regulatory matters by interveners, I see no impediment to the Commission using it to determine the prudence or reasonableness of a utility's legal costs.

[175] In summary, the Commission asked the appellants to assist in resolving matters of serious concern to the regulation of the industry. It was at least wise, if not necessary, for the appellants to participate. Accordingly, I find the appellants are entitled to recover the prudently incurred costs arising from their participation.

[176] I therefore conclude the Commission erred in law by arbitrarily denying all costs, whether prudently incurred or not, as it relates to part of the proceedings referred to in Appeal No. 1301-0069-AC. I would allow that portion of the appeal.

[177] As to Appeal No 1301-0070-AC, the Commission allowed the appellants to recover some of their legal costs, apparently those that the Commission found had been prudently incurred. I would therefore dismiss that appeal.

Appeal heard on May 9, 2014

Reasons filed at Calgary, Alberta
this 2nd day of December, 2014

Martin J.A.

Appearances:

L.E. Smith, Q.C. and
E.B. Mellett
for the Appellants

R.J. Finn
for the Respondent Alberta Utilities Commission

T.A. Shipley
for the Respondent Office of the Utilities Consumer Advocate of Alberta

13

Case Name:

REGINA v. BOARD OF COMMISSIONERS OF PUBLIC UTILITIES (N.B.), Ex parte MONCTON UTILITY GAS LTD.

[1966] N.B.J. No. 10

60 D.L.R. (2d) 703

New Brunswick Supreme Court, Appeal Division

Bridges, C.J.N.B., Ritchie, West, JJ.A.

Judgment: December 30, 1966

(125 paras.)

Counsel:

J. F. H. Teed, Q.C., for applicant, appellant.

Henry E. Ryan, Q.C., for respondent.

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1 **BRIDGES, C.J.N.B.**:--This is an appeal by the Moncton Utility Gas Limited, hereinafter referred to as the distributor, from an order made on February 19, 1966, by the Board of Commissioners of Public Utilities, hereinafter referred to as the Board, setting the rates to be charged it by the New Brunswick Oilfields Limited, hereinafter referred to as the producer, for natural gas. The appeal comes before us by way of a writ of *certiorari* as provided by s. 25(1) of the *Public Utilities Act*, R.S.N.B. 1952, c. 186, but we have under the section power to decide any question of fact upon the evidence taken before the Board and to confirm, modify, vary or reverse any order made by it.

2 In its application to the Board the distributor sought to have the rates for natural gas charged it by the producer, which were fixed in 1962, as follows:

> 1.10 per m.c.f. (thousand cubic feet) for the first 5,000 m.c.f. per month, $1.00 for the next 7,500 c.f. per month and $4.00 per m.c.f. for gas in excess of 12,500 c.f. per month.

reduced to

> 25 cents per m.c.f. for the first 3,000 m.c.f. per month, 40 cents per m.c.f. for the next 6,000 m.c.f. per month and 45 cents per m.c.f. for any gas in excess of 9,000 m.c.f. per month, the same to be retroactive to January 1, 1962.

3 After hearing the application, the Board made an order fixing the rates as follows:

> 90 cents per m.c.f. for the first 5,000 m.c.f. per month, 80 cents per m.c.f. for the next 7,500 m.c.f. per month and $4.00 per m.c.f. for any gas in excess of 12,500 m.c.f. per month.

for a period of one year, at the termination of which it was directed they would be reviewed.

4 The distributor is on this appeal asking that we further reduce the rates to those sought in its application to the Board.

5 The area from which the natural gas is produced is in Albert County and known as the Stoney Creek field. It has only an area of approximately three square miles. It is a very small field and the only location east of Ontario where natural gas is obtained in commercial quantities. The gas is delivered to the distributor about 50 ft. from the well head. It is sold to consumers in and outside the City of Moncton and the Village of Hillsboro. Moncton is some eight miles distant from the field and Hillsboro about five or six miles. The number of m.c.f. delivered by the producer in 1965 to the distributor was 102,055.

6 The field, from which oil is also obtained, was held for many years by the New Brunswick Gas & Oilfields Ltd. which had a lease of 10,000 square miles in New Brunswick from the Province. In 1947 this company disposed of its assets to the producer for $1,250,000. At that time there were in operation in the field 33 wells producing gas, 22 wells both gas and oil and six wells only oil. Except for natural gas used by the producer, the Moncton Electricity and Gas Company Limited was then, as is the distributor, purchasing all the output of gas for delivery to consumers, of whom there were in 1947 over 6,000. The price paid the New Brunswick Gas & Oilfields Ltd. by the Moncton Electricity & Gas Co. Ltd. was then 20[cent] per m.c.f. for gas delivered for domestic customers and slightly less for commercial. This had been fixed by an agreement, which was excepted by statute from the jurisdiction of the Board and had been in effect for many years.

7 In 1947 the rate for natural gas was raised to 40[cent] per m.c.f. by the Board, that body having been given jurisdiction in that year. I think the order specified 20[cent] of the 40[cent] was to be used for exploration, in any event it was understood that the increase was for such purpose as there was then at times a considerable shortage of gas for consumers. More wells were sunk with no material improvement in the supply of gas. Since 1947 there has been a decrease each year in the number of consumers. At the present time it is estimated the present supply in the field will last only 12 years though if compressors are used it may be extended to 22 years.

8 In 1957 the rate was increased by the Board to $1.50 per m.c.f. with a penalty of $4 for over 12,500 m.c.f. received by the distributor in any month. This increase was apparently not opposed. At the same time the Moncton Electricity & Gas Ltd. was granted permission to increase its rate to consumers from $1.30 to $2.70 m.c.f. The increase to $1.50 per m.c.f. was undoubtedly made to discourage the use of natural gas.

9 In 1959 the distributor was incorporated and purchased from the Moncton Electricity & Gas Co. Ltd. its natural gas distributing system for $25,000. I think it significant from the amount paid that the natural gas operation of that company was far from profitable. There is evidence that it would be a waste of money to drill further wells in the Stoney Creek field. In view of the definite limit to the amount of natural gas remaining in the field, which is generally known, it will, I think, be difficult for the distributor to obtain more consumers.

10 In 1960 the distributor built a propane gas plant in the City of Moncton and with cost of repairs and renewing old pipes etc., has spent over $300,000. It is undoubtedly the intention of the distributor to deliver propane gas through its system to consumers when the supply of natural gas terminates. I believe that the distributor has on occasions in servicing consumers used propane gas with the natural gas, but this is not now being done.

11 On November 14, 1962, the price of natural gas to the distributor was reduced to the rates in effect when the present application came before the Board. They are set out in the first page of this judgment. The order made by the

Board in 1962 fixing these rates was made with the consent of the distributor.

12 The purchase of the assets of the New Brunswick Gas & Oilfields Ltd. in 1947 was undoubtedly made by the producer with some expectation that more gas and oil would be found in and near the Stoney Creek area and elsewhere in the 10,000 miles under lease from the Province. For exploration and drilling rights the producer has received from Shell Oil and Imperial Oil the sums of $300,000 and $150,000 respectively, but after extensive drilling by these companies, Shell Oil spending upwards of $2,000,000 and Imperial Oil about $1,250,000, of which the producer contributed $237,000, no gas or oil was discovered in commercial quantities. In addition, one Orville Parker under an arrangement with the producer spent about $750,000 in drilling on the lands under lease but with the exception of a few wells in the Stoney Creek area none was productive.

13 The lease held by the producer has been reduced to include only 7,000 square miles. No exploration or drilling operations are at the present time being carried on by the producer or others under arrangements with it. It would seem that the producer is satisfied that no further natural gas or oil is to be obtained in New Brunswick in commercial quantities.

14 In 1962 West Decalta Petroleums Limited, a western Canadian company, obtained control of the stock of the producer. The latter has participated the last few years in the acquisition of areas in Alberta, British Columbia and Saskatchewan in which it is believed gas and oil may be obtained. After it obtained control West Decalta imposed a management fee of $30,000 per annum on the producer. This has been reduced to $20,000 chargeable to the Stoney Creek field. Prior to West Decalta obtaining control, large amounts were also paid out in management fees.

15 The natural gas business of the distributor, which also sells appliances, has not been successful. In 1960 it had 3,033 customers whereas in 1965 the number was 2,318. The number of m.c.f. which it sold to users in 1960 was 77,309. This has fallen to 65,485 in 1965. In 1942 when production was at its peak over 600,000 m.c.f. were sold by the Moncton Electricity & Gas Co. Ltd. and since then the quantity has gradually decreased to the present level. A net loss has been suffered by the distributor each year since it commenced business, such annual losses running from $15,000 to $26,000. At the present time it owes the producer over $148,000. It was contended on the argument that if the price of natural gas to the distributor was substantially reduced, it would pass some of such reductions in its rates to users, and, as a result, additional users would be obtained. This I greatly doubt. The situation appears to be approaching hopelessness.

16 There is a marked difference in the amount of natural gas purchased by the distributor and that delivered by it to customers. While 65,485 m.c.f. were sold by the distributor to users in the year ending March 31, 1965, the producer actually delivered 102,055 m.c.f. to it. While I think the difference has been to some extent due to leaks in the pipes and obsolete meters which do not register properly, I cannot but feel that it is also caused by the water vapour content of the gas. In October, 1962, the producer commenced injecting water into the wells for the purpose of improving the production of oil and I think it has had some effect. The distributor has installed two dehydrators and conditions may improve. There is a loss of approximately 35% whereas in some systems it is as low as 71/2%

17 The grounds of appeal are that the Board erred:

1. In not fixing the rates upon the principle applied and accepted as correct in the *Phillips Rate Case* (1960), 35 P.U.R. (3rd) 199 later approved of by the Supreme Court of the United States.

2. In not fixing rates in line with the well head rates for natural gas paid to producers elsewhere in Canada and United States, the highest of such rates being according to the evidence 33[cent] per m.c.f.

3. If the principle in the *Phillips Rate Case* is not applicable, in fixing rates (90 and 80[cent] per

m.c.f.), higher than those which the justice of the case required.

4. In fixing a penal rate of $4 per m.c.f. on gas in excess of 12,500 m.c.f. per month.

5. In holding that it had no jurisdiction to make the rates fixed by its order retroactive to January 1, 1962, or to some appropriate date.

6. In not reducing the rates to such a level that the distributor would be financially able to pass part of such reduction to its customers and provide a new schedule to such effect.

7. In not ordering the producer to deliver clear gas.

18 I can see no reason why there should be a penal rate of $4 per m.c.f. for gas in excess of 12,500 m.c.f. per month. This is, in my opinion, discriminatory. Nor do I think we should consider the seventh ground, which is already the subject of a counterclaim in an action between the producer and distributor. This disposes of these grounds. The first and second may be considered together as also I think the third and sixth.

19 In the *Phillips Rate Case*, on which the first and second grounds are based, it was held that the appropriate method for determining natural gas rates was an area pricing method which would fix such rates as nearly as might be reasonable with the market rates established by bargaining between producers and purchasers in an area where many producers were competing for business. The producer in the case at bar has no competitor and there are in fact no other producers in New Brunswick nor within approximately 1,000 miles from here. I think it would be unfair to fix the rates on what other producers are receiving in other parts of Canada as contended on behalf of the distributor. It would be taking the entire country as one area. In my opinion the *Phillips Rate Case* should not be applied.

20 I come to the fifth ground that the Board has power when fixing a rate to order that it be made retroactive. Section 6(1) of the *Public Utilities Act*, reads:

> 6(1) Upon complaint made in writing to the Board that any rates, tolls, charges or schedules of any public utility are in any respect unreasonable, insufficient or unjustly discriminatory, or that any regulation, measurement, practice or act whatsoever affecting or relating to the operation of any public utility is in any respect unreasonable, insufficient or unjustly discriminatory, or that the service of any public utility is inadequate or unobtainable, or that any public utility should extend its services to any district without such services, the Board shall proceed, with or without notice, to make such investigation as it deems necessary or expedient, and may order such rates, tolls, charges or schedules reduced, modified or altered, and may make such other order as to the modification or change or such regulation, measurement, practice or act as the justice of the case may require, and may order, on such terms and subject to such conditions as are just, that the public utility furnish reasonably adequate service and facilities, and may order that the public utility shall extend its services to a district without such services, upon such terms and subject to such conditions as the Board may deem just.

21 In *Bakery & Confectionery Workers International Union of America, Local 4.68 v. Salmi, White Lunch Ltd. v. Labour Relations Board of British Columbia*, 56 D.L.R. (2d) 193, [1966] S.C.R. 282, 55 W.W.R. 129, which was relied upon by counsel for the distributor, the Supreme Court of Canada held that the Labour Relations Board of British Columbia could by its order vary a certification order, which it had made, by changing the name of the employer and make such change in the certification order retroactive to the day it was made. Section 65(3) [enacted 1961, c. 31, s. 37(c)] of the *Labour Relations Act*, R.S.B.C. 1960, c. 205 of that Province reads:

> 65(3) The Board may, upon the petition of any employer, employers' organization, trade-union, or other person, or of its own motion, reconsider any decision or order made by it under this Act, and may vary or cancel any such decision or order, and for the purposes of the Act the certification of a trade-union is a decision of the Board.

22 The order in the *Bakery & Confectionery Workers'* case for the change in the certification order did not rescind the latter which still stood as a valid order after the alteration had been made. In the case before us the order made by the Board in 1962 fixing rates was not altered but completely superseded by the order of February 19, 1966, which fixed new rates. Such order contained no reference to the order of 1962, but it cannot be questioned that it had this effect. Section 6(1) of our *Public Utilities Act* does not specifically provide for the alteration of an order of the Board, but for the reduction or alteration of rates. Section 65(3) of the *Labour Relations Act* of British Columbia provides very definitely for the variation of an order.

23 Section 14 of the *Public Utilities Act* provides that until new schedules are filed all rates in force at the passing of the Act "shall be lawful rates ... until the same are altered, reduced or modified as herein provided". It could not have been the intention of the Legislature that after it had declared a rate lawful, the Board could render such declaration as of no effect as would be the case if a few months after the passing of the Act the Board ordered a reduction in a rate and made it retroactive to the date of the Act.

24 In the *Bakery & Confectionery Workers'* case, Hall, J., in referring to what Bull, J.A., stated in the Court below [51 D.L.R. (2d) 72], said at p. 204:

> However, he limited the effect of s. 65(3) by holding that the word "vary" in the section "cannot be used as an excuse for bringing retroactively into being a new unit of employees for which the Union stands certified ..." I cannot read the section as narrowing the plain meaning of the word "vary". It is defined in the Shorter Oxford English Dictionary as: "To cause to change or alter; to adapt to certain circumstances or requirements by appropriate modifications" nor do I accept the view that the word "vary" cannot apply retroactively. It has not such a limited meaning and circumstances will frequently arise where it must have a retroactive effect. The present case is a classical example.

25 It is to be noted that Hall, J., does not say that the word "alter", which means the same as "vary" and includes "reduce" in respect to a rate should in all cases have the meaning he gave it. I do not think, to use his language, that circumstances have arisen for the words "reduce" or "alter" to be given the interpretation sought by the distributor. If the Board has power to make retroactive rates in the present case, it has, because of the wording of the section, likewise authority to do so when ordering an increase in rates to consumers upon application of a distributor. In such a case there would be hundreds of users called upon to pay the difference between the old and new rates. This would be most unreasonable. I cannot give such an interpretation to the section. It is my opinion that neither the word "reduce" or "alter" in s. 6(1) of our *Public Utilities Act* should be interpreted as giving the Board the authority when fixing a rate to direct that it be retroactive. Even if I am wrong in my view, I would have no hesitation in holding that any new rates set in this case should not be made retroactive as the distributor consented to the order in 1962 fixing the rates which it now seeks to have further reduced.

26 I come to the third and sixth grounds of appeal. Subsection (3) of s. 6 of the Act reads:

> 6(3) In making an order under this section the Board shall take into consideration the reasonableness of the rate of return to the public utility upon its investment.

27 Section 10 of the Act is as follows:

> 10. Every public utility shall furnish reasonably adequate service and facilities, and all charges made by a public utility shall be reasonable and just, and every unjust or unreasonable charge is

prohibited and declared unlawful.

28 It was contended on behalf of the distributor that under s. 10 the Board was not obligated to fix a rate that would yield a reasonable return to the public utility on its investment. With this I cannot agree. This would not be fair. Persons would be loathe to operate a public utility under such circumstances. While there may be occasions, when owing to special circumstances, a rate not yielding a reasonable return may be fixed, it cannot, in my opinion, be allowed to stand indefinitely. A public utility is entitled to a reasonable rate of return on its investment.

29 It was argued on behalf of the distributor that the producer was engaged in three lines of business, (1) the exploration of 9,997 square miles of the 10,000 square miles in the Province of New Brunswick for gas and oil, (2) the production of oil in the Stoney Creek field and (3) the production of gas in the same field and that each should stand on its own footing.

30 It is my opinion that in 1947 the producer became engaged in only two lines of business or ventures. The first was the production of gas and oil in the Stoney Creek field and the further exploration of that field and vicinity for more gas which could be supplied in the system in use for consumers in the City of Moncton and outside its limits. The increase of 20[cent] per m.c.f. allowed in 1947 was, I think, for only such exploration. The second venture was the exploration for gas and oil in the remainder of the 10,000 acres.

31 In 1950 the Board made an order establishing a rate base of $770,427 which I gather was arrived at by taking the purchase price of $1,250,000 and deducting therefrom moneys received for exploration rights, depreciation and depletion. This rate base was not questioned until 1962. I am not prepared to hold the Board was in error in establishing it. In their 1962 report, Reevey, Blackmore, Burnham & Laws, a firm of chartered accountants, stated the rate base was then either $254,943 or $403,092.

32 There has been a reduction in the management fee of $30,000 charged soon after West Decalta obtained control to $20,000. Even this I consider excessive. The gross revenue of the entire undertaking is less than $150,000. To me, unless good reason to the contrary is shown, $5,000 to $7,500 would be an appropriate fee.

33 I think the oil should be regarded as a by-product of the gas. The producer would in all probability not be engaged in the production of oil were it not for the gas. I think some consideration should be given to the extent the gas should pay for the oil. A number of expenditures relate to both but there are some which concern only oil. In 1964 the expenditures relating to oil alone exceeded the revenue from oil by nearly $5,500.

34 There is evidence that an engineer is no longer employed at the Stoney Creek field. His salary was approximately $10,000 per annum. The operation apparently does not require a full-time engineer and there should be a considerable saving in this connection.

35 In fixing the rates for only one year the Board was strongly influenced by the fact there might in the meantime be a considerable reduction in the unaccounted for gas of about 36,000 m.c.f. I do not think this was an unreasonable view to take. The financial statement of the producer for the year 1964 showed receipts of $120,683 and expenditures of $121,389, the result of which was a net loss of $706. Included in the expenditures were allowances of over $7,000 for depreciation, approximately the same amount for depletion and $27,000 for doubtful accounts. The last amount was for a portion of what was owing to the producer by the distributor for gas for which the latter had not paid. The Board was of the opinion that this was not a normal expenditure. I do not think it should be considered in fixing rates. It arose because the rates were too high for the distributor to be able to pay them. If lower rates are reasonable, I think they should be set although the distributor is in debt to the producer.

36 The Board was of the opinion that the producer and distributor should each have an equitable share of what profits were available and that for this to result the cost of the gas to the distributor should be reduced by $20,000 per annum. As it refused to recognize as a debit in the expenditures of the producer the allowance of $27,000 for doubtful debts, it therefore regarded the producer as having a profit of $26,294 in 1964. I am not certain how the Board arrived at the amount of $20,000 as it is not stated in the reasons. It would seem to me that it was probably due to the fact that such amount deducted from $26,294 would leave the producer a profit of over $6,000 in 1964 and a reduction of the expenditures of the distributor by $20,000 would turn the loss of $13,515 shown for the year ending March 31, 1965, on its natural gas operation into also a profit of over $6,000. In addition, however, to the loss of $13,515 shown on the 1965 statement of the distributor there also appears a debit separate therefrom of $14,627 which was the difference between interest charges of $20,535 and $5,908, the profit from the non-utility business of the distributor. I expect these interest charges relate for the most part to the propane gas plant of the distributor.

37 The Board does not mention the excessive management fee paid and the fact a full-time engineer is no longer necessary. I think these matters should be given careful consideration when the rates are reviewed as well as the loss on oil. Because of them I have given some thought to reducing the rates set by the Board, but am of the opinion we should not interfere.

38 I would allow the appeal but only to the extent of varying the order of the Board by deleting the charge of $4 per m.c.f. for gas in excess of 12,500 m.c.f. per month. The provision for a review after one year is to stand. There will be no costs.

39 RITCHIE, J.A.:--This appeal from an order of the Board of Commissioners of Public Utilities of the Province of New Brunswick comes before us by way of *certiorari* pursuant to s. 25 of the *Public Utilities Act*, R.S.N.B. 1952, c. 186. The order fixed the rates to be paid by Moncton Utility Gas Ltd. for natural gas purchased by it from New Brunswick Oilfields Ltd. I adopt the statement of relevant facts set out in the reasons for judgment of my Lord the Chief Justice. Any additions I may make to that statement will be for a special purpose.

40 For convenience of reference sometimes hereinafter the Board of Commissioners of Public Utilities will be referred to as "the board", Moncton Utility Gas Limited as "the distributor", New Brunswick Oilfields Limited as "the producer" and the *Public Utilities Act* as "the Act".

41 The order of February 9, 1966, the subject of the appeal now before us, is based on a unanimous decision of the board set out in "Reasons For Order" bearing the same date. The board found that:

(a) under current operating conditions, there were insufficient earnings available to provide an adequate return to either the producer or the distributor;

(b) it was necessary to adjust the well head prices in order to

  (i) continue the supply of natural gas to the ultimate consumer,

  (ii) provide each company with sufficient income to cover its operating expenses and, to the extent available, its depletion and depreciation charges;

  (iii) provide, to the extent available, both companies with income sufficient to produce an adequate return on the capital investment of each of them; and

(c) in order to provide each company with an equitable share of the total profits available, it was necessary to reduce the "transfer cost" of natural gas by approximately $20,000.

42 For those express purposes the board fixed new well head prices payable by the distributor of:

0.90 per m.c.f. for the first 5,000 m.c.f. per month;

0.80 per m.c.f. for the next 7,500 m.c.f. per month;

4.00 per m.c.f. for any gas in excess of 12,500 m.c.f. per month.

43 Based on the sales volume of the distributor for its fiscal year ending March 31, 1965, but not allowing for any contraction or expansion thereof, the 1966 operating expenses being the same as in 1965 and the 1965 loss of $28,000, the rate reduction should reduce the 1966 loss of the distributor to an amount approximating $5,000. The new rates and the elimination of a provision for doubtful accounts, regarded by the board as improper, will produce a small theoretical profit for the producer. Comparison of the operating results of the two companies is complicated by the difference in their fiscal periods. The fiscal year of the producer ends on December 31st. Exercise of the supervisory jurisdiction of the board would be facilitated if the fiscal periods of the two companies coincided with the calendar year.

44 The application for an order directing the producer to deliver clean dry gas to the distributor was dismissed. The reasons supporting the order state the new rates had been fixed on the basis the distributor must accept gas from the producer in the same condition as it emerged at the well head.

45 The board also directed a further review of the rate schedule be conducted at the expiration of one year. Uncertainty as to the extent it was possible to eliminate the loss resulting from unaccounted for gas delivered to the distributor's distribution system appears to have been the principal reason motivating the direction there be a further rate review at the expiration of one year.

46 Western Decalta Petroleums Ltd. acquired voting control of the producer in 1962. The following year the producer's operations were extended to Western Canada. A loss of $51,844 was incurred in respect of the 1963 operations of the producer in that area. The operating loss in New Brunswick was $11,986. Interest and other income of $19,736, however, reduced to $44,094 the 1963 total loss in both New Brunswick and Western Canada. The 1964 operating loss in New Brunswick was $706 and in Western Canada $12,907. Interest and other income of $15,987 reduced the net 1964 loss in the two areas to $2,374.

47 Operating expenses shown on the producer's profit and loss statements include provision for doubtful accounts of $6,528 in 1962 and $27,000 in the year 1964. In regard to the provision for doubtful accounts in those two years, Messrs. Clark-son, Gordon & Co., the auditors of the producer, state:

> These provisions relate to the outstanding account receivable from Moncton Utility Gas Limited which at December 31, 1964 amounted to $94,737 and which has since increased to $148,138 at October 31, 1965.

48 We do not have before us any financial statement of the producer as of December 31, 1965.

49 The m.c.f. volume of gas sold by the producer to the distributor in the 1961-1965 period and the gross revenue resulting therefrom have been:

Year ended May 31, 1961	101,663 m.c.f.	$152,495.00
Year ended May 31, 1962	83,960 m.c.f.	125,940.00
Seven months ended December 31, 1962	53,313 m.c.f.	71,990.00
Year ended December 31, 1963	102,114 m.c.f.	108,114.00
Year ended December 31, 1964	105,428 m.c.f.	111,428.00
Ten months ended October 31, 1965	83,582 m.c.f.	88,582.00

50 For the seven months ended December 31, 1962, and the fiscal years ending December 31, 1963, and 1964, the profit and loss results from the New Brunswick operations of the producer have been:

	1962	*1963*	*1964*
Loss	($6,063.00)	($11,986.00)	($706.00)

51 "Interest and other income" of $20,010, however, converted the 1962 operating loss of $6,063 on the New Brunswick operations into a net profit of $13,947. It was not until 1963 that the producer extended its field of endeavour to Western Canada.

52 A submission by Messrs. Clarkson, Gordon & Co., to the board, made under date of December 11, 1965, is of interest. One passage reads:

> The Board appears to have agreed in the past that oil production in New Brunswick is essentially a by product of the gas operations. This is the opinion expressed in the report of Messrs. Reevey, Blackmore, Burnham, Laws and Page dated August 9, 1962. We concur with this opinion. In our view also, it would not be feasible to segregate all expenses between oil and gas, even if it were considered proper to do so, and that the present volume of business activity would not justify the maintenance of the detailed records necessary for more detailed cost allocations. The company's records therefore segregate costs only to the extent of the directly identifiable production expenses as shown in Schedule V. This is consistent with the basis used in the 1962 report to which we have previously referred.

53 Schedule V lists the following figures in respect of oil operations:

	For Seven Months Ended Dec. 31, 1962	For Year Ended Dec. 31, 1963	For Year Ended Dec. 31, 1964
Sales	$23,155.00	$28,495.00	$13,077.00
Less Royalties	407.00	529.00	326.00
	$22,748.00	$27,966.00	$12,751.00
Less production expenses	17,395.00	23,361.00	18,236.00
Operating revenue or (loss)	$ 5,353.00	$ 4,605.00	$(5,485.00)

54 If the year end figures for 1965 and 1966 also show a loss on oil production it would seem the board should review the policy of regarding oil production as a by-product of the gas operations and not segregating expenses between oil and gas.

55 Depreciation and depletion write-offs by the producer in the 1962-1964 period were:

	1962	*1963*	*1964*
Depreciation	$ 5,873.00	$ 9,800.00	$ 7,227.00
Depletion	4,122.00	6,948.00	7,243.00
	$ 9,995.00	$16,748.00	$14,470.00

56 Over the years the producer has spent $697,216 on exploration and development work.

57 There has been a steady decline in the business of the distributor. In no year have its operations produced a profit. For the six full fiscal years since its incorporation, the distributor's volume of sales, number of customers and operating results have been:

Year	*Number of Customers at End of Year M.C.F.*	*Loss*
1960	3,033 77,309	$26,649
1961	2,948 74,624	17,575
1962	2,904 74,576	27,944
1963	2,719 72,806	15,177
1964	2,507 67,918	25,181
1965	2,318 (not audited) 65,485	28,000
	Total loss (amount of deficit account)	$140,526

58 The number of customers and the quantity of gas sold were less and the amount of the loss greater in 1965 than in any of the five preceding years. As of March 3, 1965, the distributor's current liabilities exceeded current assets by

$84,392.20.

59 The depreciation write-offs by the distributor in the 1962-1965 period have been:

1962	--	$ 5,105.00
1963	--	$ 2,908.00
1964	--	$ 9,314.00
1965	--	$12,402.00

60 The appeal is based on seven grounds. The first and second grounds may be dealt with together. They are:

> 1. The board erred in not fixing the rates in accordance with the principles discussed and accepted as correct in the "Phillips Rate Case" decided by the United States Federal Power Commission in 1960, affirmed by the District of Columbia Court of Appeal and later (1963) by the Supreme Court of the United States.
>
> 2. The board erred in not fixing the rates "in line" with the well head rates for natural gas paid producers elsewhere in Canada and the United States.

61 The distributor concedes the only production of natural gas in New Brunswick is in the Stoney Creek Field but contends an "area price" may be obtained by examination of the well head prices prevailing throughout Canada or even throughout North America. No pipeline carries gas into New Brunswick from any other Province of Canada or the United States. There is one small producing field in Ontario, almost 1,000 miles distant.

62 Phillips Petroleum Company, the company from which the *Phillips Rate Case* derived its name, is a large integrated oil company which also produces natural gas. It is known as an "independent" producer of gas and is not affiliated with any interstate gas pipeline company. It owns gathering systems and holds leases in Kansas, Oklahoma, New Mexico, along the Gulf Coast of Texas and in other scattered localities. In 1954, the test year selected to determine its cost of service, Phillips expended more than $47,474,039 in exploration and development expenses. Exploration costs of the producer in New Brunswick have been

1963	--	$25,142.00
1964	--	$17,894.00

63 Much of the gas sold by Phillips in interstate commerce was purchased from thousands of other independent producers. In 1960 it was selling more natural gas in the United States than any other oil and gas producer. In addition to the production of oil, gasoline and natural gas, the company carried on other operations. It was then the largest producer of liquids condensed from natural gas. The Phillips sale of natural gas in 1954 were 688,811,312 m.c.f. The distributor sold 65,485 m.c.f. in 1965.

64 *Re Phillips Petroleum Co.* (1960), 35 P.U.R. (3d) 199 was a rate proceeding before the Federal Power Commission of the United States of America. At p. 208 of the Commission decision the following passage appears:

> Experience of the commission in this case, as well as in many other producer rate cases during the last five years, has shown, beyond any doubt, that the traditional original cost, prudent investment rate base method of regulating utilities is not a sensible, or even a workable, method of fixing the rates of independent producers of natural gas.

65 On the same page, the Commission expressed the opinion that

> Producers of natural gas cannot, by any stretch of the imagination, be properly classified as traditional public utilities.

66 The basic conclusion of the Commission was that the "ultimate solution" for determining the rates to be charged by independent producers of natural gas lay in what had come to be known as

> the area rate approach: the determination of fair prices for gas, based on reasonable financial requirements of the industry for each of the various producing areas of the country.

67 Such determination is made on an area, rather than on an individual company, basis. See *Wisconsin et al. v. Federal Power Commission* (1963), 48 P.U.R. (3d) 273 (U.S.S.C.). The Supreme Court of the United States approved the Commission finding that the individual company cost-of-service method is not a feasible or suitable one for regulating the rates of independent producers of natural gas and expressed the hope the area approach might prove to be the ultimate solution.

68 The definition of public utility, found in s. 1(c) of the Act, includes

> a person owning, operating, managing or controlling ... any plant or equipment ... for the production, transmission, delivery or furnishing of ... gas ... either directly or indirectly, to or for the public.

69 Under that statutory definition, both the producer and the distributor are public utilities. The Federal Power Commission declaration that producers of natural gas should not be classified as *traditional* public utilities has, therefore, little, if any, application to the status of either the producer or distributor. Subsections (1) and (3) of s. 6 of the Act confer on the board jurisdiction to fix the rates public utilities may charge. Those two subsections are:

> 6(1) Upon complaint made in writing to the Board that any rates, tolls, charges or schedules of any public utility are in any respect unreasonable, insufficient or unjustly discriminatory, or that any regulation, measurement, practice or act whatsoever affecting or relating to the operation of any public utility is in any respect unreasonable, insufficient or unjustly discriminatory, or that the service of any public utility is inadequate or unobtainable, or that any public utility should extend its services to any district without such services, the Board shall proceed, with or without notice, to make such investigation as it deems necessary or expedient, and may order such rates, tolls, charges or schedules reduced, modified or altered, and may make such other order as to the modification or change of such regulation, measurement, practice or act as the justice of the case may require, and may order, on such terms and subject to such conditions as are just, that the public utility furnish reasonably adequate service and facilities, and may order that the public utility shall extend its services to a district without such services, upon such terms and subject to such conditions as the Board may deem just.

> (3) In making an order under this section the Board *shall take into consideration the reasonableness of the rate of return to the public utility upon its investment*. [Italics added.]

70 Subsection (3) of s. 6 was introduced in 1935 [c. 29, s. 1], following the 1934 judgment in *The King v. Board of Commissioners of Public Utilities, Ex p. Maritime Electric Co.*, [1935] 1 D.L.R. 456, 9 M.P.R. 1 (N.B.C.A.). There it was held this Court was bound by the decision of the Privy Council in *Canada, Southern R. Co. v. International Bridge Co.* (1883), 8 App. Cas. 723 and could not consider the reasonableness of the rate on the basis of the return to the company upon its investment. Baxter, J., as he then was, had said [p. 461]:

> It has been said that the modern theory of rate making is that rates should be based upon cost to the producer rather than upon the value of the service to the consumer, the cost including the return which the owners receive for the use of capital and for the management of the business. It is with regret that I come to the conclusion that the Public Utilities Act, R.S.N.B. 1927, c. 127, does not displace the common law rule that the reasonableness of rates is to be determined by the value of the service to the consumer and not by the return to the person or company supplying the service. If the Act permitted the Commission to hear an application against an unreasonable return as well as against an unreasonable rate they would have complete jurisdiction, but that is not the language of the statute and we are absolutely bound by the decision of the Privy Council in the *Canada Southern R. Co. v. Intel-national Bridge Co.*, 8 App. Cas. 723 followed and applied in *Rickett, Smith & Co. v. Midland R. Co.*, [1896] 1 Q.B. 260 and *Ex p. Moncton T.E. & G. Co.*, [1927] 3 D.L.R. 1112.

71 The wording of s-s. (3) is clearly ambiguous and mandatory. The board now must consider "the reasonableness of the rate of return to the public utility upon its investment". The price for gas sold by the producer to the distributor is to be determined by the circumstances and local considerations pertaining to the volume, quality and production cost of natural gas at Stoney Creek together with, as required by s. 6(3), the return on the investment, or rate base, of the producer. We are not now bound by *The King v. Board of Commissioners of Public Utilities, Ex p. Maritime Electric Co., supra*.

72 The area rate principle, as enunciated in the *Phillips Rate Case*, can have no application to the determination of rates for the purchase of gas produced in the Stoney Creek Field, an isolated pocket producing only a small volume of gas.

73 The third and fourth grounds of appeal also may be dealt with together. They are:

> 3. If such principle (I assume the "in line" with the rates of other producers principle) is not applicable, the board erred in fixing the new basic rates (90[cent] and 80[cent] per m.c.f.) higher than those which the "justice of the case required".
>
> 4. The board erred in fixng any penal rate, or alternatively, a penal rate of $4.00 per m.c.f. (almost five times the basic rate for any gas taken in excess of 12,500 m.c.f. per month).

74 Section 6(1) provides the board

> may make such other order as to the modification or change of such regulation, measurement, practice or act as the justice of the case may require ...

75 The record does not disclose what return on the recognized investment of the producer (its rate base) the board considered the rates set by the February 19, 1966, order would produce. Also lacking is a precise statement of the amount the board accepted as the correct rate base of the company as of the date of that order. A rate base means the value of the property used and useful in furnishing the service, including necessary working capital. *The King v. Rideout et al., Ex p. Moncton Electricity & Gas Co. Ltd.*, [1949] 4 D.L.R. 612, 65 C.R.T.C. 217, 24 M.P.R. 303 *sub nom. The King v. Board of Commissioners of Public Utilities, Ex p. Moncton Electricity & Gas Co. Ltd.*

76 In the course of argument it was stated to us that in 1950, during the hearing of an application of the producer for an increase in the rates chargeable by it to Moncton Electricity & Gas Company Limited, the then distributor, hereinafter sometimes referred to as "Moncton Electricity", but at which, for some reason which does not appear, Moncton Electricity was not represented, the board made an order establishing a rate base for the producer of $770,427. The increase in rates granted to the producer at that time was estimated to produce a return of 5.87% on the $770,427 investment. No objection to the establishment of that rate base was taken by Moncton Electricity or by the present distributor until 1962, 12 years after it had been determined. The objection then was advanced by the distributor in the course of the hearing which resulted in the November 14, 1962 consent order. When, in 1959, it bought the distribution system of Moncton Electricity, the distributor was aware, or should have been aware, of the existence and amount of the producer's rate base as determined by the board.

77 In a report prepared for the board dated August 9, 1962, Messrs. Reevey, Blackmore, Burnham, Laws & Page, chartered accountants, discuss the rate base of the producer, which they state was *established in 1957*, and provide data relevant to an application then before the board seeking approval of a new rate schedule for the sale of natural gas to the distributor by the producer. For convenience of reference, this report sometimes hereinafter will be referred to as "the Reevey report". It states the value, as of May 31, 1962, of the leases and rights held by the company to be $277,120 computed as follows:

Amount paid by the company	
for assets -- 1947	$1,250,000.00
Less	
Appraised values	
Land and plant	$206,041.00
Inventories	92,853.00 298,894.00
	$ 951,106.00
Less	
Amounts received from Shell	
Exploration New Brunswick	
Limited for sub-lease	$305,000.00
Amounts received from Imperial	
Oil Limited for sub-lease	150,000.00 455,000.00
	$ 496,106.00
This leaves the following	
position:	
Residual cost of leaseholds	$ 496,106.00
Less: Depletion charged to	218,986.00
31 May 1962	$ 277,120.00

78 Because they believed little justification had been established for the estimate of *probable* reserves of gas and oil within the area of the producer's lease, the authors of the Reevey report recommended a change in the method of computing depletion rates for determination of the rate base. They also recommended depreciation of fixed assets be recomputed on a straight-line method. Using the revised methods of computation so recommended, the Reevey report determines the rate base as at May 31, 1962 to be $254,943. That amount is made up of:

Investment in leases	$496,106.00	
Less: Amount amortised	367,033.00	$129,073.00
Fixed assets	308,293.00	
Less: Accumulated		

depreciation	261,423.00	46,870.00
Provision for stores		
and supplies		63,000.00
Provision for working		
capital		16,000.00
		$254,943.00

79 The Reevey report concedes however, that had depletion of the leases been computed on the basis formerly used, they would have determined the rate base, as of May 31, 1962, to be $403,092. The Reevey recommendations, so far as the record discloses, were not accepted by the board.

80 The Clarkson, Gordon & Co. submission (*supra*) asserts adoption of the lower ($254,943) base would effectively deny to the shareholders of the producer any return on the difference between $403,092 and $254,943. The Clarkson firm maintains $403,092 was the correct rate base as of May 31, 1962.

81 Before this Court, counsel for the distributor pressed the submission there was not in New Brunswick, or in any other Canadian jurisdiction, legislation declaring that, in fixing rates to be charged by a public utility and particularly in fixing rates to be charged by a producer of natural gas, regard should be had to a rate base. In support of that submission, decisions of the Supreme Court of the United States and the Federal (U.S.) Power Commission were cited.

82 Section 6(1) of the Act enables the board to order that the rates, tolls, charges or schedules of any public utility be reduced, modified or altered. Reference already has been made to s-s. (3) which expressly requires the board to consider the reasonableness of the rate of return to a public utility upon its investment. The probable return on the investment to be produced by any alteration of the rate schedule of a public utility may not be the controlling factor in determining a new rate schedule but such return cannot be excluded from the consideration of the board. A rate schedule which is not sufficient to provide any return is, in my opinion, unreasonable.

83 Counsel for the distributor further submitted that

(a) while s. 6(3) gives the board jurisdiction to take into consideration the fact that existing rates gave a public utility an unreasonable return on its investment, it did not obligate, or even authorize the board to fix a rate which would yield a reasonable, or any, return on such investment; and

(b) s-s. (3) did not alter the principle stated in s. 10 that all rates shall be "reasonable and just", meaning reasonable and just to the purchaser.

84 Section 10 of the Act is:

> 10. Every public utility shall furnish reasonably adequate service and facilities, and all charges made by a public utility shall be reasonable and just, and every unjust or unreasonable charge is prohibited and declared unlawful.

85 The definition of public utility contained in s. 1 (*c*) includes a person owning, operating, managing or controlling any plant or equipment for the production, transmission, delivery or furnishing of gas, either directly or indirectly to the public.

86 I entertain no doubt that, whenever reducing, modifying or altering the rates to be charged by the producer for gas delivered to the distributor, the board should take into consideration the reasonableness of the rate of return upon the investment of the producer. To maintain stability in its operations, a public utility must operate at a profit. In examining the probable rate of return on the existing rate base of the producer, the board should have regard to the reasonableness of all the operating costs charged by the producer to gas production in the Stoney Creek Field. Unfortunately, we do not know the amount the board regarded as the proper rate base on February 19, 1966.

87 In regard to the rate of return earned by the producer on the rate base as computed by them, the Clarkson, Gordon submission (*supra*) states:

> The statement of profit and loss for the periods ended December 31, 1962 and 1964 include provisions for doubtful accounts receivable of $6,528 and $27,000 respectively. These provisions relate to the outstanding account receivable from Moncton Utility Gas Limited which at December 31, 1964 amounted to $94,737 and which has since increased to $148,138 at October 31, 1965. For purposes of calculating the rate of return theoretically earned by New Brunswick Oilfields, Limited, these charges have been removed from the operating expenses.

The adjusted earnings will then be as follows:

	Seven Months Ended December 31, 1962	Year Ended December 31, 1963	Year Ended December 31, 1964
Operating Loss--New Brunswick	$ (6,063)	$ (11,986)	$ (706)
Plus exploration costs capitalized			(17,894)
Plus adjustment of depreciation to straight line rates	(681)	(402)	(2,551)
Less provision for doubtful accounts	6,528		27,000
	$ (216)	$ (12,388)	$ 5,849

Rate Base

> The Reevey Report (page 7) determines the rate base at May 31, 1962 at either $254,943 or $403,092. The lower base resulted from re-calculating the depletion rate and would have effectively denied any return to the shareholders on the difference between the two amounts. In our present calculations, we have used $403,092 as the correct rate base at May 31, 1962 and have adjusted this amount for subsequent changes in investment. The year-end balance are as shown below.

	December 31,	December 31,

December 31,	1962	1963	1964
Investment in oil and gas properties	$498,020	$507,353	$512,121
Less amount amortized	223,108	230,056	237,299
	274,912	277,297	274,822
Fixed assets	316,622	301,171	291,799
Less accumulated depreciation	266,970	259,175	262,969
	49,652	41,996	28,830
Provision for stores and supplies	62,000	50,000	42,000
Provision for working capital	16,000	16,000	16,000
Rate Base	$402,564	$385,293	$361,652

Rate of Return

> Based on the adjusted earnings and the rate at the end of each year as shown above, the theoretical rate of return for the periods under review have been as follows:

Seven months ended December 31, 1962	(0.1)%
Year ended December 31, 1963	(3.2)%
Year ended December 31, 1964	1.6%

> It must be recognized that the above rates do not reflect the fact that the substantial account receivable from Moncton Utility Gas Limited has not been paid.

> The rates as determined above are significantly lower than rates normally earned by gas utility companies in Canada and the United States.

88 The return of 1.6% shown as earned on the rate base in 1964 is a theoretical, not a cash, return. The account of the distributor had not been paid.

89 In *The King v. Rideout et al., Ex p. Moncton Electricity & Gas Co. Ltd.* (*supra*), this Court increased the rate of yield to 7% upon the rate base. At pp. 622-3, Harrison, J., said:

> The principles upon which the rate of return should be fixed are well stated in the judgment of the Supreme Court of the United States in the case of *Bluefield Water Works & Improvement Co. v. Public Service Com'n* (1923), 262 U.S. 679 at p. 692: "What annual rate will constitute just compensation depends upon many circumstances and must be determined by the exercise of a fair and enlightened judgment, having regard to all relevant facts. A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time and become too high or too low by changes affecting opportunity for investment, the money market and business conditions generally".
>
> The above judgment was also quoted with approval by the Board of Transport Commissioners in *Ottawa v. Ottawa Electric R. Co.* (1946), 59 C.R.T.C. 136 at p. 168.

90 Also at pp. 623-4:

> While I realize that upon questions of fact the findings of the Board should be treated like those of a trial Judge in accordance with the decision in *Ruddy v. Toronto Eastern R. Co.* (1917), 33 D.L.R. 193, 21 C.R.C. 377, 38 O.L.R. 356, and *Toronto Suburban R. Co. v. Everson* (1917), 34 D.L.R. 421, 54 S.C.R. 395, yet the matter of return is not a finding upon facts but a conclusion from facts, and a matter of opinion as to which this Court is in as good a position as the Board to give a decision.
>
> The Board do not mention the high profits made by the company in preceding years as a ground for their decision, but do not state that these profits have not been considered. They also rely upon what they term "the rather secure position of the company". Inasmuch as the company's contract with the City of Moncton for supply of electrical power terminates on March 26, 1950, when the company may be taken over by the city, I cannot regard the company as being in a stable position. I would increase the rate of yield to 7% upon the rate base.

91 In their "reasons" for the February 19, 1966, order the board state:

> The financial statement of the distributor for the year ended March 31, 1965 indicates that it operated at a loss of some $13,000.00 after providing some $15,000.00 for depreciation.
>
> The financial statement of the producer for the year ended December 31, 1964 shows a loss of $706.00 after making a provision of $27,000.00 for doubtful accounts and approximately $15,000.00 for depreciation and depletion. In my view, the provision for doubtful accounts of $27,000.00 is not a normal operating expense. Therefore, the result for the year was actually a $26,000.00 operating profit.

> Upon analyzing the financial statements of both the producer and the distributor, I find that there are insufficient profits available under current operating conditions to provide an adequate return to both companies. To continue the supply of natural gas to the ultimate consumers, it becomes necessary to adjust the wellhead price of gas to ensure that each company shall receive firstly sufficient income to cover its necessary cash operating expenses, secondly, to the extent available, income to meet its depletion and depreciation costs and finally, to the extent available, income to provide an adequate return on capital investment.
>
> I further find that for the year ended March 31, 1965, 102,000 m.c.f. were transferred at the wellhead at an approximate cost of $107,000.00. In order to provide each company with an equitable share of the total profits available to the two companies for return on capital, it is necessary to reduce the transfer cost of natural gas by approximately $20,000.00.

92 I take the last sentence to mean that by so reducing the "transfer cost" both the producer and distributor would have income available to apply on "return of capital". Income of that nature must be actual income, not theoretical income.

93 For the fiscal year ended December 31, 1964, the net receipts (gross sales less royalties) of the producer from the sale of 105,428 m.c.f. of gas and 4,857 barrels of oil amounted to $120,063. The "transfer cost" of the gas at well head was $111,428. Operating costs, as charged to the New Brunswick operation by the producer, including the $27,000 provision for doubtful accounts, totalled $121,389. Through the disallowance of the $27,000 write-off, the board converted the operating loss of $706 shown in respect of the New Brunswick operations into a theoretical, or paper, profit, of $26,294.

94 I presume it was on the basis of an *actual operating profit* of $26,294 being substituted for the 1964 operating loss of $706 shown on the company books that the board determined the transfer cost of natural gas should be reduced by approximately $20,000. The board appears to have brushed aside as of no consequence the alarming state of the account owing by the distributor to the producer. Nothing in the record suggests the new rates will enable the distributor to pay that account in the foreseeable future.

95 With respect, I cannot accept the view of the board that the 1964 provision of $27,000 for bad and doubtful accounts was not a proper charge against revenue. The account receivable from the distributor was increasing at an alarming rate. As of December 31, 1964, the amount alleged owing was $94,737. The account remained unpaid. It continued to increase at a rate averaging $5,400 per month.

96 The producer, however, appears to have accepted the disallowance of the provision for doubtful accounts. Its factum states, "The respondent agrees with the board order and the reasons for the order". The views I now express apply, therefore, to the propriety of this Court directing a further reduction in the rates fixed by the board.

97 If the 1966 m.c.f. sales volume of gas is the same as in 1964 and the transfer cost of gas at well head is $20,000 less, the net dollar salus volume of the producer for gas and oil will be $100,683. If the $27,000 write-off for doubtful accounts is eliminate d but all other 1966 operating expenses are the same as in 1364, total operating costs will be $94,389. The result will be a theoretical profit of $6,294. That is equivalent to a return of 1.7% on $361,652, the amount the Clark-son submission states was the correct rate base on December 31, 1964. While the yield would, of course, be larger on the lower 1966 rate base it still would be inadequate and, in my view, unreasonable.

98 Even without any provision whatsoever for doubtful accounts, it is obvious the producer cannot reduce its rates by any amount approximating $20,000 and obtain a reasonable return on its investment. A reasonable return must be predicated on a reasonable profit. The content of the third paragraph quoted from the "reasons" of the board indicate they realized the new rates would not realize revenue sufficient for the producer to earn a reasonable profit. A public utility producing natura gas should not be required to operate on an estimated revenue not sufficient to permit reasonable provisions for depletion, depreciation and doubtful accounts. The rates fixed in 19 50 were estimated to produce a return of 5.87% upon the rate base of the producer.

99 As I read the financial statements, they provide no support for the view of the board that the reduced rates would provide each company with "an equitable share of the total profits available to the two companies for return of capital". The producer already has an accrued operating deficit of $9,628. It will be interesting to see what that figure will be as of December 31, 1966.

100 The rate of $4 per m.c.f. applicable to any gas delivered in excess of 12,500 m.c.f. per month is a penal rate designed to discourage any increased use of domestic gas from the Stoney Creek Field. Section 10 states, "every unjust or unreasonable charge is prohibited and declared unlawful". The board has no authority to fix a penal rate. It cannot be classified as "reasonable and just". The consent of the parties to a penal rate being fixed by the board did not render it lawful. The $4 rate for any gas delivered in excess of 12,500 m.c.f. per month should be set aside.

101 While it is my opinion the new rates are confiscatory in their impact on the producer, it has accepted them. On the further review of the rate schedule which will commence in February, 1967, the board will have before them the operating results of both companies for 1965 and 1966. In such circumstances, I would not now interfere further with the existing schedule. I will content myself with offering suggestions as to some items of operating expense I believe should be scrutinized in the course of the 1967 review.

102 The fifth ground of appeal is that

> the board erred in holding it had no jurisdiction to make the new rates retrospective to a date prior to the order and in not ordering they be effective either as from January 1, 1962 or as from some other appropriate date prior to February 19, 1966.

103 The distributor contends that in the absence of any express limitation or restriction or an express provision as to the effective date of any order made by the board, the jurisdiction conferred on the board by the Legislature includes jurisdiction to make orders with retrospective effect. Reliance is placed on *Bakery and Confectionery Workers International Union of America, Local 468 v. Salmi, White Lunch Ltd. v. Labour Relations Board of British Columbia*, 56 D.L.R. (2d) 193, [1966] S.C.R. 282, 55 W.W.R. 129 which it is contended must be applied when interpreting s. 6(1) of the Act.

104 The clear object of the Act is to ensure stability in the operation of public utilities and the maintenance of just, reasonable and non-discriminatory rates. That object would be defeated if the board having, on November 14, 1962, made an order fixing the rates to be paid by the distributor for natural gas purchased from the producer, reduced those rates on February 19, 1966, more than three years later, and directed the reduced rates be effective as from January 1, 1962, or as from any other date prior to February 19, 1966.

105 Assuming the Act does confer on the board jurisdiction to direct that rates fixed by any order be retrospective to a date prior to the date of the order, the consent of the distributor to the November 14, 1962, order constituted, in my opinion, a compelling reason for the board not to direct the rate reduction have any retroactive effect.

106 It follows I would not interfere with the effective date of the order appealed from. In such circumstances, the question raised by the fifth ground of appeal becomes academic. It has been raised, however, and is certain to be raised again in the not too distant future, perhaps at the February, 1967, review of the rates chargeable by the producer. I, therefore, deem it fitting that I express my opinion on the question of the jurisdiction of the board to make retrospective orders.

107 The cardinal rule for the construction of a statute is that it should be construed according to the intention expressed in the statute itself. The duty of the Court is to interpret the words the Legislature has used. When interpreting the language of any enactment it is natural to enquire what is the subject-matter with respect of which the language is used. The object of the legislation must be considered from a common-sense viewpoint. If the words of the statute are themselves precise and unambiguous, then no more is necessary than to expound those words in their ordinary and natural sense. Speculation should not be indulged in: *Crates on Statute Law*, 6th ed., p. 66; *Maxwell on Interpretation of Statutes*, 10th ed., p. 2.

108 In view of the stress placed by the distributor on *Bakery & Confectionery Workers International Union of America, Local 468 v. Salmi (supra)*, I will refer to it in some detail. That appeal concerned a variation made in an order certifying a bargaining agent to represent a bargaining unit of employees. The Labour Relations Board of British Columbia had reconsidered a certification order made by them and varied it by substituting another company for that named as the employer in the original certification order. The shares of the two companies were owned by the same individuals. They had the same general manager and the same president. Their operations were interrelated. Shortly after the original certification order was made, steps were taken to wind up the company named as the employer therein. The trade union which had been certified as the bargaining agent then, relying on s. 65(3) [enacted 1961, c. 31, s. 37(*c*)] of the *Labour Relations Act*, R.S.B.C. 1960, c. 205, applied to the board to have the certification order varied by substituting the second company as the employer. That section of the *Labour Relations Act* read:

> 65(3) The Board may, upon the petition of any employer, employers' organization, trade-union, or other person, or of its own motion, reconsider any decision or order made by it under this Act, and may vary or cancel any such decision or order, and for the purposes of the Act the certification of a trade-union is a decision of the Board.

109 The Labour Relations Board ruled the section conferred authority on it to make the variation sought and granted the application. The company, seeking to have the order quashed, instituted *certiorari* proceedings. The Judge [42 D.L.R. (2d) 364] to whom the application was made quashed the Labour Relations Board order. The appeal of the trade union to the British Columbia Court of Appeal [51 D.L.R. (2d) 72] was dismissed. A further appeal to the Supreme Court of Canada was, however, allowed. The basis on which the Supreme Court of Canada interpreted s. 65(3) is set out at pp. 201-2 of the D.L.R. volume. There Hall, J., delivering the judgment of the Court, says:

> The respondent's main contention is that s. 65(3) does not give the Board jurisdiction to amend the orders previously made in the manner done on February 13, 1962. Counsel for the respondent, citing well-known authorities, emphasized that the provisions of the *Labour Relations Act* being in derogation of common law rights should be strictly construed. On the other hand, counsel for the appellants urged that the *Labour Relations Act* was remedial legislation and should be liberally construed.
>
> Whatever merit the arguments of the respondent had at the beginning of labour relations legislation, it seems to me that in the stage of industrial development now existing it must be accepted that legislation to achieve industrial peace and to provide a forum for the quick determination of labour-management disputes is legislation in the public interest, beneficial to employee and employer and not something to be whittled to a minimum or narrow interpretation in the face of the expressed will of Legislatures which, in enacting such legislation, were aware that common law rights were being altered because of industrial development and mass employment which rendered illusory the so-called right of the individual to bargain individually with the corporate employer of the mid-twentieth century.

110 The Court declined to interpret the section so as to narrow the plain meaning of the word "vary", declined to adopt the view that the word "vary" could not apply retroactively; held the decision of the board was, by statute, final and conclusive; and ruled the Court would not and must not interfere in what had been done within the board's jurisdiction. In support of that ruling, reference was made to the statement of Lord Sumner in *R. v. Nat Bell Liquors Ltd.*

, 65 D.L.R. 1 at pp. 22-3, 37 C.C.C. 129, [1922] 2 A.C. 128, [1922] 2 W.W.R. 30, in which:

> ... it would itself, in turn, transgress the limits within which its own jurisdiction of supervision, not of review, is confined. That supervision goes to two points: one is the area of the inferior jurisdiction and the qualifications and conditions of its exercise; the other is the observance of the law in the course of its exercise.

111 The *Bakery & Confectionery Workers'* case is, in my opinion, readily distinguishable. The order we are dealing with is not an alteration or variation of an already existing order. It is a new order made in substitution for a previous order. A *Public Utilities Act* and a *Labour Relations Act* are two entirely different types of legislation. The Supreme Court held s. 63(3) clearly conferred on the Labour Relations Board jurisdiction to vary the certification order; that they had decided to vary it; and that, in *certiorari* proceedings, there could be no interference with their decision as to the nature of the variation. A decision of the New Brunswick Board of Commissioners of Public Utilities is not final. It is subject to appeal, by way of *certiorari*. We have jurisdiction to decide, upon the evidence before the board, any question of fact and to confirm, modify, vary or reverse the order made by the board.

112 The precise and unambiguous words comprising the language of the Act should be interpreted in their ordinary and natural sense. There are no gaps in the language of the Act which require filling in. In no section of the Act do I find any wording indicating an intention on the part of the Legislature to confer on the board authority to make orders fixing rates with retrospective effect or any language requiring a construction that such authority has been bestowed on the board. To so interpret s. 6(1) would render insecure the position of not only every public utility carrying on business in the Province but also the position of every customer of such public utility.

113 I do not find it necessary to discuss the sixth ground of appeal which is:

> the board erred in not reducing the rates to be paid by the appellant for natural gas to such a level that the appellant would be financially able to pass part of such reduction on to its customers and present a new schedule of rates to be paid to it by its customers for gas as prayed for in item 4(1)(b) of the petition.

114 The seventh ground of appeal is that

> the board erred in not ordering the producer to deliver clean dry gas to the distributor.

115 Since 1962 or 1963 the producer has been experimenting with injecting, under high pressure, large quantities of water into the Stoney Creek wells. The object of such injection is to increase the oil production. What success the experiment has attained has yet to be determined. It did, however, impose on the distributor the problem of dealing with the "wet gas" which was a direct result of the experiment. To combat the wet gas, the distributor, at its own expense, has installed two dehydrators at the points where the gas is delivered to it.

116 As the quality of the gas delivered by the producer to the distributor is one of the issues between the parties in the Queen's Bench Division action, I refrain from expressing any opinion as to whether the rates fixed by the board apply only to gas in its natural state; or whether the rates also apply to gas which the producer has diluted by the injection of water.

117 My examination of the financial statements of the producer indicates that included in its operating costs are some items the board should submit to close scrutiny on the 1967 rate review. While I propose referring to them, the reference is only intended as a suggestion they be considered carefully. I have no thought of attempting to impose my views on the board.

118 The $20,000 management fee charged the producer by its controlling shareholder appears to be unreasonable. The producer should be required to justify a management fee of $20,000 or any other amount.

119 During the 1964 fiscal period the producer lost $5,485 in producing and marketing lubricating oil. I doubt if, in a situation such as exists in the Stoney Creek Field, the producer should be permitted to charge that loss as an operating expense in the production of natural gas. It may be the 80-20 cost allocation is outdated.

120 Another operating charge which should, I suggest, be reviewed is the $10,000 item covering the salary of an engineer. It is doubtful if the scope and nature of the operations the producer presently is engaged in require employment of a full-time engineer.

121 I would allow the appeal but only to the extent of eliminating the penal rate for $4 per m.c.f. fixed by the order of the board for all gas in excess of 12,500 m.c.f. delivered in any one month.

122 I would make no order as to costs.

123 WEST, J.A.:--I have read the reasons for judgment of the other members of the Court, and agree that the appeal should be allowed only to the extent of eliminating the penal rate of $4 per m.c.f. for all gas in excess of 12,500 m.c.f. delivered in any one month.

124 I refrain from expressing any opinion on the fifth ground of the appeal. The consent of the appellant to the order of November 14, 1962, is a sufficient reason for not giving retroactive effect to the order of the Board of February 19, 1966. It is unnecessary to decide in this case whether or not an order of the Board may be made retroactive.

125 I would allow the appeal to the extent I have indicated above. I would make no order for costs.

14

Ontario Energy Board

Commission de l'énergie de l'Ontario

EB-2013-0321

IN THE MATTER OF AN APPLICATION BY

ONTARIO POWER GENERATION INC.

PAYMENT AMOUNTS FOR PRESCRIBED FACILITIES FOR 2014 AND 2015

DECISION WITH REASONS

November 20, 2014

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EB-2013-0321

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O.1998, c.15, (Schedule B);

AND IN THE MATTER OF an application by Ontario Power Generation Inc. pursuant to section 78.1 of the *Ontario Energy Board Act, 1998* for an Order or Orders determining payment amounts for the output of certain of its generating facilities.

BEFORE: Marika Hare
Presiding Member

Christine Long
Member

Allison Duff
Member

DECISION WITH REASONS

NOVEMBER 20, 2014

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Appendix F - Final Prioritized Issues List

EXECUTIVE SUMMARY

This is the Decision of the Ontario Energy Board (the “Board”) regarding an application filed by Ontario Power Generation Inc. (“OPG”). OPG is the largest electricity generator in Ontario. Provincial regulation requires that the Board set the rates that OPG charges for the generation from its nuclear facilities (Pickering and Darlington) and most of its hydroelectric facilities (e.g. Sir Adam Beck I and II on the Niagara River). The rates charged by OPG are referred to as payment amounts and are expressed in dollars per megawatt-hour ($/MWh). These payment amounts are included in the electricity costs which are shown as a line item on the electricity bill from a customer’s distributor, and make up about half the total of an average household bill.

Payment amounts for electricity generated from OPG’s two nuclear facilities and six of its hydroelectric facilities (on the Niagara, Welland and St. Lawrence Rivers) were last set for the period 2011 and 2012. These amounts remained in place for 2013 as OPG did not file a payment amounts application for 2013. Payment amounts are set by the Board in accordance with provincial regulations which stipulate, among other matters, which facilities are included in the payment amounts. As of July 1, 2014 these facilities include 48 hydroelectric plants that were not previously covered by the regulation. These hydroelectric plants are referred to as the “newly regulated” hydroelectric facilities in this Decision.

If the payment amounts were approved by the Board as proposed by OPG, the bill impact on a typical residential customer would be an increase of $5.31 per month, or a 23.4% increase over current payment amounts. However, this Decision adjusts numerous elements that factor into the calculation of the resulting payment amounts. These include elements such as costs, revenues, taxes and production forecasts. The approximate impact on the payment amounts as a result of this Decision is an increase of 10% over the payment amounts that OPG is currently paid, a significant reduction over the increase requested by OPG. This is an approximation only, as the exact number cannot be determined until OPG reflects all aspects of this Decision that factor into the calculation of the resulting payment amounts.

OPG filed an incomplete application at the end of September 2013. The proceeding leading to this Decision was extremely lengthy, due to the delay in the filing of a complete application, several updates to the evidence from December 2013 to July

2014, and complexities associated with the amount of information for which confidential treatment was sought.

In reaching its findings, the Board was aided by the participation of 20 parties, representing diverse customer interests and policy matters, and Board staff. The Board also took note of 41 letters of comment received from customers and numerous independent consultant reports. In addition, the Auditor General's report[1] was filed in this proceeding and provided context to OPG's human resources issues.

This Decision of the Board addresses issues in the detail required to set the payment amounts for 2014 and 2015. The Decision is organized into the following major sections: introduction, regulated hydroelectric facilities, nuclear facilities, corporate matters, design of payment amounts and implementation of the Decision. Key highlights of this Decision include:

- Reduction in OPG's proposed Operations, Maintenance and Administration budget in both the nuclear and hydroelectric sides of the business mainly due to excessive compensation. The reductions total $100 M per year.
- Approval of a $1,364.6M addition to rate base due to the completion and in-service addition of the Niagara Tunnel, a reduction of $88M from what OPG had requested to be included.
- Approval of the in-service additions associated with the Darlington Refurbishment project for 2014 and 2015.
- Denial of the request for approval of commercial and contracting strategies with respect to the Darlington Refurbishment project.
- Rejection of the accrual method of accounting for determining pension and other post-employment benefit costs for ratemaking in 2014 and 2015.
- Adjustment of the debt:equity ratio from 53:47 to 55:45.
- Direction to OPG to undertake independent and comprehensive benchmarking studies for the hydroelectric business and for corporate support costs, and to undertake a comprehensive compensation study.
- Effective date for the commencement of these new payment amounts will be November 1, 2014.

[1] Annual Report of the Auditor General of Ontario, Chapter 3.05 OPG Human Resources, December 10, 2013 (Exh KT2.4)

1 INTRODUCTION

Ontario Power Generation Inc. filed an application with the Ontario Energy Board on September 27, 2013. The initial application was deemed by the Board to be incomplete, and the complete application was not filed until December 5, 2013. The application was filed under section 78.1 of the *Ontario Energy Board Act, 1998*, S.O 1998, c. 15 (Schedule B) (the "Act"), seeking approval for payment amounts for OPG's previously regulated hydroelectric facilities and nuclear facilities for the test period January 1, 2014 through December 31, 2015, to be effective January 1, 2014. The application also seeks approval for payment amounts for newly regulated hydroelectric facilities to be effective July 1, 2014. The Board assigned the application file number EB-2013-0321.

OPG requested, and the Board issued, an order declaring the current payment amounts interim for the previously regulated hydroelectric facilities and nuclear facilities as of January 1, 2014 and for the newly regulated hydroelectric facilities as of July 1, 2014, pending the Board's final decision.

1.1 Legislative Requirements

Section 78.1(1) of the Act establishes the Board's authority to set the payment amounts for the prescribed generation facilities. Section 78.1 can be found at Appendix A of this Decision. Section 78.1(4) states:

> The Board shall make an order under this section in accordance with the rules prescribed by the regulations and may include in the order conditions, classifications or practices, including rules respecting the calculation of the amount of the payment.

Section 78.1(5) states:

> The Board may fix such other payment amounts as it finds to be just and reasonable,
>
> (a) on an application for an order under this section, if the Board is not satisfied that the amount applied for is just and reasonable; or

(b) at any other time, if the Board is not satisfied that the current payment amount is just and reasonable.

Ontario Regulation 53/05, *Payments Under Section 78.1 of the Act,* ("O. Reg. 53/05") provides that the Board may establish the form, methodology, assumptions and calculations used in making an order that sets the payment amounts. O. Reg. 53/05 also includes detailed requirements that govern the determination of some components of the payment amounts. O. Reg. 53/05 can be found at Appendix B.

On November 27, 2013, O. Reg. 53/05 was amended to require regulation by the Board of 48 additional hydroelectric stations.

1.2 The Prescribed Generation Facilities

OPG owns and operates both regulated and unregulated generation facilities. As set out in section 2 of O. Reg. 53/05, the regulated, or prescribed, facilities consist of six previously regulated hydroelectric generating stations and two nuclear generating stations. As amended in November 2013 and set out in section 2 and the schedule of O. Reg. 53/05, the newly regulated hydroelectric facilities are comprised of 48 stations. OPG operates these stations in 4 plant groups, as shown in the table below. The regulated facilities produce more than half of the electricity consumed in Ontario.

Table 1: Prescribed Generation Facilities

Previously Regulated Hydroelectric		Newly Regulated Hydroelectric		Nuclear	
Station	MW	Plant Group	MW	Station	MW
Sir Adam Beck I	427	Ottawa St. Lawrence	1,526	Pickering Units 1&4	1,030
Sir Adam Beck II	1,499	Central Hydro	108	Pickering Units 5-8	2,064
Sir Adam Beck PGS	174	Northeast	818	Darlington	3,512
DeCew Falls I	23	Northwest	658		
DeCew Falls II	144				
RH Saunders	1,045				
TOTAL	**3,312**		**3,110**		**6,606**

In 2010, the operations of Pickering Units 1 and 4 (formerly referred to as Pickering A) and Pickering Units 5 - 8 (formerly referred to as Pickering B) were amalgamated into a single station.

OPG also owns the Bruce A and B nuclear generating stations. These stations are leased on a long term basis to Bruce Power L.P. Under section 6(2)9 of O. Reg. 53/05, the Board must ensure that OPG recovers all the costs it incurs with respect to the Bruce nuclear generating stations. Under section 6(2)10 of O. Reg. 53/05, the revenues from the lease, net of costs, are to be used to reduce the payment amounts for the prescribed nuclear generating stations.

OPG has entered into a Memorandum of Agreement with its shareholder. This Memorandum sets out the shared expectations of OPG and its shareholder regarding OPG's mandate, governance, performance and communications. Included in its provisions related to the nuclear mandate are expectations related to continuous improvement, benchmarking, and improved operations. The Memorandum is reproduced at Appendix C.

1.3 Previous Proceedings

The current application is OPG's third cost of service application. The previous proceedings were assigned file numbers EB-2007-0905 and EB-2010-0008.[2]

In 2012, OPG filed an application, EB-2012-0002, seeking approval to adopt Generally Accepted Accounting Principles of the United States ("USGAAP") for regulatory accounting purposes and to clear 2012 year-end deferral and variance account balances for all accounts except for four. Parties to the proceeding achieved settlement and the Board accepted the settlement proposal. The EB-2012-0002 decision established payment amount riders for 2013 and 2014 to clear the 2012 account balances. In this proceeding OPG proposes disposition of the four accounts not previously cleared in EB-2012-0002.

1.4 The Application

The application filed on September 27, 2013 was underpinned by OPG's 2013-2015 business plan. The application, as filed, was deemed by the Board to be incomplete and OPG filed additional evidence on December 5, 2013 to meet the Board's filing

[2] The EB-2010-0008 decision was appealed by OPG. The appeal was dismissed at the Divisional Court. OPG was successful before the Ontario Court of Appeal. The Court of Appeal's decision has now been appealed to the Supreme Court of Canada, and that appeal is expected to be heard in December 2014.

requirements. If approved, the application would result in an increase of $5.36 on the monthly total bill for a typical residential customer consuming 800 kWh per month. This information was published in the Notice of Application in 88 newspapers throughout the province.

OPG filed an impact statement on December 6, 2013 (Exhibit N1) that updated the application to reflect material changes in costs and production forecasts for the 2014-2015 period which were included in OPG's 2014-2016 business plan. As the bill impact resulting from the Exhibit N1 update would result in an increase of $5.94 on the monthly total bill, the Board determined that further notice was required.

A second impact statement was filed on May 16, 2014 (Exhibit N2) to update the application to reflect material changes in costs and production forecasts that had arisen since the first impact statement was filed in December 2013. The bill impact of the subsequent Exhibit N2 update was proposed to be an increase of $5.31 per month. Based on the Exhibit N2 update, OPG is seeking an increase of 23.4% on payment amounts.

The proposed revenue requirement, as updated on May 16, 2014, is summarized in the following table.

Table 2: Proposed Revenue Requirement

$million	Previously Regulated Hydroelectric		Newly Regulated Hydroelectric		Nuclear		
	2014	2015	2014 [1]	2015	2014	2015	TOTAL
Expenses OM&A[2]	145.1	140.0	117.5	237.3	2,401.4	2,419.8	5,461.1
Gross Revenue Charge/Nuclear Fuel	267.2	280.8	37.8	77.5	266.5	260.5	1,190.3
Depreciation	82.1	81.9	31.1	63.1	273.7	288.5	820.4
Property Tax	0.3	0.3	0.1	0.1	15.9	16.4	33.1
Income Tax	49.7	64.2	15.0	42.7	108.3	16.8	296.7
Cost of Capital Short-term Debt	3.6	4.6	0.9	2.3	1.6	2.1	15.1
Long-term Debt	127.0	126.2	31.1	62.7	57.4	58.3	462.7
Return on Equity	225.6	227.7	55.3	113.2	101.9	105.3	829.0
Adjustment for lesser of UNL or ARC[3]					74.6	70.3	144.9
Other Revenue	(34.0)	(34.6)	(11.4)	(23.1)	(33.2)	(30.5)	(166.8)
Bruce Net Revenue					(39.7)	(40.6)	(80.3)
Revenue Requirement	866.6	891.1	277.3	575.8	3,228.4	3,166.9	9,006.1
Deferral and Variance Accounts		70.6				62.2	132.8
Note 1: The newly regulated hydroelectric revenue requirement reflects July 1, 2014							
Note 2: OM&A - Operations, Maintenance and Administration Costs							
Note 3: UNL - unfunded nuclear liability, ARC - asset retirement cost							

To achieve the revenue requirement and disposition of balances in the four deferral and variance accounts, OPG requested the payment amounts and riders shown in the following table, which also provides the current payment amounts and riders.

Table 3: Payment Amounts and Riders

$/MWh	Previously Regulated Hydroelectric	Newly Regulated Hydroelectric	Nuclear
Current			
Payment Amount	35.78		51.52
Rider (2013)[1]	3.04		6.27
Rider (2014)[1]	2.02		4.18
Proposed			
Payment Amount	42.75	47.57	67.60
Rider (2015)	3.36		1.35

Note 1: Payment Amount Riders established by EB-2012-0002

A summary of the approvals that OPG is seeking in the current application is found at Appendix D.

1.5 The Proceeding

Details of the procedural aspects of the proceeding are provided at Appendix E.

In the EB-2010-0008 decision, the Board stated that it "will explore with OPG and stakeholders how best to identify issues in the next proceeding to ensure that the highest priority issues are identified early." The Board also expressed concern that "an inordinate focus on lower priority issues diminishes the time and resources available to pursue the more substantive, higher priority issues." As a result, the Board established a process for categorizing primary and secondary issues in this cost of service proceeding and made provision for a settlement process for certain issues. Any unsettled primary issues would proceed to oral hearing and any unsettled secondary issues would proceed to written hearing.

The Board convened a settlement conference between OPG and the parties on May 21 to 26, 2014. No settlement was achieved. The Board established the final prioritized issues list for the proceeding in June, 2014. That issues list is found at Appendix F.

The Board received 41 letters of comment in response to the Notices of Application. The Board has reviewed each of these letters. The letters raise a variety of issues, many of which are dealt with in this Decision. Many of the letters of comment expressed concern about the request to increase payment amounts and the difficulty customers faced in paying current electricity bills without any additional increase. Although the Board will not address each letter specifically, the comments have been taken into account in the Board's deliberations.

Two parties applied for, and were granted, observer status. Twenty parties applied for and were granted intervenor status. The submissions of the following parties are referred to in this Decision: Association of Major Power Consumers in Ontario ("AMPCO"), Canadian Manufacturers & Exporters ("CME"), Consumers Council of Canada ("CCC"), Energy Probe Research Foundation ("Energy Probe"), Environmental Defence, Green Energy Coalition ("GEC"), Independent Electricity System Operator ("IESO"), Lake Ontario Waterkeeper ("Waterkeeper), London Property Management Association ("LPMA"), Power Workers' Union ("PWU"), School Energy Coalition ("SEC"), Society of Energy Professionals ("Society"), Sustainability-Journal and Vulnerable Energy Consumers Coalition ("VECC").

During the proceeding, confidential treatment was sought for a large number of documents.

This Decision addresses issues in the detail required to set the payment amounts for 2014 and 2015. The Decision is organized into the following major sections: the regulated hydroelectric facilities, nuclear facilities, corporate matters, design of payment amounts and implementation of the Decision.

2 REGULATED HYDROELECTRIC FACILITIES

2.1 Hydroelectric Production Forecast

(Issues 5.1 and 5.2)

At the highest level, OPG's payment amounts result from a simple equation: OPG's reasonably incurred costs divided by the number of megawatt-hours it is expected to produce (i.e. the production forecast). The production forecast put forward by OPG, therefore, is a major input in the calculation of final payment amounts. OPG proposed for the Board's approval a production forecast of 32.5 TWh[3] for 2014 and 33.5 TWh for 2015.

OPG's historical hydroelectric production and production forecast for 2014 and 2015 are summarized in the following table. The production includes the Niagara Tunnel Project which went into service in March 2013.

Table 4: Hydroelectric Production Forecast

TWh	2010 Actual	2011 Approved	2011 Actual	2012 Approved	2012 Actual	2013 Budget	2013 Actual	2014 Plan	2015 Plan
Niagara	12.4	12.9	12.6	12.9	11.9	12.2	12.4	12.8	13.5
Saunders	6.5	7.0	6.9	7.0	6.5	6.2	6.5	6.3	6.7
Sub-Total	**18.9**	**19.9**	**19.5**	**19.9**	**18.4**	**18.4**	**18.9**	**19.1**	**20.2**
Newly Regulated	10.0		11.5		10.9	12.4	12.5	12.4	12.5
Total	**28.9**		**31.0**		**29.3**	**30.8**	**31.4**	**31.5**	**32.7**
Exhibit N1 Update - Previously Regulated only, no change for Newly Regulated								**32.5**	**33.5**
Source: Exh E1-1-2, Exh L-1-Staff-2, Exh N1-1-1									

OPG uses computer models to predict water flow and production forecast for the previously regulated hydroelectric facilities and the larger of the newly regulated hydroelectric facilities. The production forecast for the 27 smaller newly regulated hydroelectric facilities is based on historical production.

The hydroelectric water conditions variance account captures the impact of the difference between forecast and actual water conditions for the previously regulated hydroelectric facilities. OPG proposes that the variance account also apply to the larger of the newly regulated hydroelectric facilities.

[3] One terawatt-hour = 1,000,000 megawatt-hours

OPG's production forecast did not include an adjustment for surplus baseload generation. This condition occurs when electricity production from baseload facilities (such as nuclear and hydroelectric) exceeds Ontario demand. When OPG is unable to store water in a surplus baseload generation situation, the financial impact of the foregone revenue is recorded in the surplus baseload generation variance account.

CME observed that the balances in the variance account are large and submitted that the Board should embed some level of surplus baseload generation into the payment amounts by adjusting OPG's production forecast. In reply, OPG submitted it did not disagree with CME's proposal, but chose to maintain the Board-approved approach in EB-2010-0008, utilizing a variance account rather than including a forecast production adjustment.

Board staff observed that actual surplus baseload generation in 2011 and 2012 was significantly lower than forecast for those 2 years. Board staff and several other parties submitted that the production forecast, without surplus baseload generation adjustment, was appropriate.

Board Findings

The Board accepts the hydroelectric production forecast as filed. The forecast methodology was based on the methodology used in EB-2010-0008 for the previously regulated hydroelectric production forecast. The same production forecast methodology was applied to the larger of the newly regulated hydroelectric assets. The hydroelectric production forecast of 66.0 TWh (32.5 TWh for 2014 and 33.5 TWh for 2015) is reasonable.

OPG provided estimates of surplus baseload generation in 2014 and 2015 for information purposes only, not for the purpose of adjusting its hydroelectric production forecast and revenue requirement calculation. As a result, the Board does not find it necessary to comment on the 2014 and 2015 estimates provided, as the actual revenue implications will be captured in the surplus baseload generation variance account.

The Board will not implement CME's proposal to include a forecast production adjustment given the uncertainties in any surplus baseload generation forecast for the previously regulated or the newly regulated hydroelectric facilities.

2.1.1 Hydroelectric Incentive Mechanism (Issues 5.3 and 5.4)

OPG has the ability to store water at its pump generating station, and at some of its other hydroelectric facilities. Water can be "held back" during periods of low demand (and low market prices), and then released during periods of higher demand (and consequently higher market prices). Shifting production of relatively low cost hydroelectric power from periods of low demand to periods of high demand will generally benefit all consumers by lowering the market price during high demand periods.

OPG could be paid the same amount for production no matter what the market price is, however, OPG would have no built in monetary incentive to shift its regulated hydroelectric generation from periods of low demand to periods of high demand. For this reason, starting with the incentive in O. Reg. 53/05, OPG has been provided with an incentive to shift its hydroelectric production from times of low demand to times of high demand.

In OPG's last payments proceeding (EB-2010-0008) the Board found that a revised hydroelectric incentive mechanism for production from OPG's regulated hydroelectric assets was appropriate. The approved hydroelectric incentive mechanism was based on sharing 50% of the hydroelectric incentive mechanism revenues through revenue requirement adjustments, retention by OPG of an equal amount and sharing of any additional net revenues.

The EB-2010-0008 decision also directed OPG to undertake an analysis of the interaction between the hydroelectric incentive mechanism and surplus baseload generation. OPG's analysis indicated that as a result of surplus baseload generation reducing the monthly average hourly production threshold for the hydroelectric incentive mechanism, there was an unintended benefit to OPG. The 2011-2013 unintended benefit to OPG has been determined to be $6.8M.[4]

In the current proceeding, OPG has proposed an enhanced hydroelectric incentive mechanism that is based on a forecast of consumer benefits and which it considered to be administratively simpler. The mechanism would apply to both previously and newly regulated hydroelectric facilities. OPG estimates the consumer benefits resulting from

[4] Undertaking J4.7

the enhanced hydroelectric incentive mechanism to be $36M in each of 2014 and 2015 and proposes X-factor adjustments to the hydroelectric incentive mechanism and surplus baseload generation monthly calculations such that the benefits are shared and the unintended benefit to OPG is corrected. OPG's proposal also included elimination of the revenue requirement adjustment and no further additions to the hydroelectric incentive mechanism variance account.

OPG indicated that it would not change how the previously and newly regulated hydroelectric facilities are operated under the enhanced hydroelectric incentive mechanism. Under that premise, the IESO submitted that the enhanced hydroelectric incentive mechanism is acceptable from a market efficiency perspective.

Board staff submitted that the enhanced hydroelectric incentive mechanism is based on OPG's forecast of benefits and could generate results that are one-sidedly beneficial to OPG. However, OPG argued that actual benefits could be lower, so the proposal is symmetric.

Board staff submitted that the current hydroelectric incentive mechanism should be retained with revenue requirement adjustments of $22M in 2014 and $37M in 2015 to reflect the addition of the newly regulated hydroelectric facilities. While the current mechanism provides for 50:50 revenue sharing, Board staff submitted that the Board could consider a graduated sharing such that more was returned to ratepayers at higher revenue levels. Board staff submitted that an after-the-fact adjustment to the monthly average hourly production threshold that corrects for surplus baseload generation impacts should be processed. The staff submission was supported by most parties.

OPG stated that the Board staff submission is inferior to the enhanced hydroelectric incentive mechanism proposed by OPG. However, if the Board adopts the approach put forward by Board staff, the hydroelectric incentive mechanism variance account should be symmetrical, protecting both ratepayers and OPG. OPG also argued that there is no need for a graduated sharing mechanism as it would have the effect of reducing the amount of time shifting that OPG performs.

CME and VECC submitted that the December 31, 2013 balance in the surplus baseload generation account should be adjusted by the $6.8M unintended benefit. This matter is also noted in the deferral and variance account section of this Decision.

Board Findings

The Board finds that the current incentive mechanism has encouraged appropriate use of the regulated hydroelectric facilities to supply energy in response to market prices. OPG's witnesses testified that they are incented to move production from periods of low value to periods of high value, based on market signals.

The Board does not approve OPG's proposed new enhanced hydroelectric incentive mechanism. OPG failed to demonstrate to the Board that the enhanced mechanism was superior to the current mechanism in terms of incentives for OPG or benefits to ratepayers.

OPG's enhanced hydroelectric incentive mechanism proposal is predicated on forecasts of consumer cost changes and cost reductions, resulting from its customer benefits analysis. The Board finds that OPG's enhanced hydroelectric incentive mechanism proposal fundamentally shifts from a revenue sharing concept to an estimate of forecast consumer benefits.

Further, the enhanced hydroelectric incentive mechanism is dependent upon OPG's forecasts and estimates, as OPG proposes to close the variance account established by the Board in the last proceeding to any further additions. The purpose of the variance account was to enable the sharing of actual revenues above the hydroelectric incentive mechanism threshold, between OPG and ratepayers.

Board staff recommended the Board maintain the current hydroelectric incentive mechanism and direct OPG to change its monthly average hourly production threshold calculation to address any unintended benefit in 2014 and 2015. OPG has the information required to make the calculation as it provided the unintended benefit from March 2011 to December 2013. The Board sees merit in Board staff's proposal for the following reasons:

- It provides ratepayers with a revenue sharing potential beyond the forecast in the revenue requirement adjustment.
- It provides OPG with the incentive to maximize actual revenues beyond the forecast, in responding to market prices.
- It is very similar to the existing incentive, yet provides a simple way to correct for the unintended surplus baseload generation benefit.

The Board finds the structure of the current variance account appropriate as a mechanism for sharing actual revenues beyond the threshold implicit in the revenue requirement adjustment. The Board will not change the structure of the variance account and will maintain its asymmetrical structure for 2014 and 2015. The Board reiterates its findings in the EB 2010-0008 decision that this incentive is a premium paid by ratepayers to OPG so OPG will operate in a way which is of greater benefit to ratepayers. With the addition of the newly prescribed assets to the hydroelectric generating business, the forecast of benefits arising from the hydroelectric incentive mechanism has increased significantly. For this reason, the Board will change the threshold levels for sharing given OPG's forecast of benefits. A second change from the previous mechanism is to utilize 50% of the forecast in the revenue requirement.

The Board finds no compelling reason to change the revenue sharing ratio from the current 50:50 split. Alternative proposals were made in submissions only, and therefore not explored in the hearing.

As a result, the Board finds the revenue requirement will be adjusted by $39M in 2014 and $48M in 2015, which is 50% of the forecast hydroelectric incentive mechanism revenues of $78M and $96M for the previously regulated and newly regulated hydroelectric assets.[5] The next $39M of hydroelectric incentive mechanism revenues in 2014 and $48M in 2015 will be retained by OPG. Therefore, the $78M and $96M will be the new thresholds, with any additional revenues beyond those amounts shared equally between OPG and ratepayers enabled by the variance account.

OPG shall allocate the revenue requirement adjustment between the previously regulated and newly regulated hydroelectric assets as appropriate.

2.1.2 Energy Storage
(Issue 5.1(a))

Sustainability-Journal submitted that the use of energy storage to meet peak demand instead of peak generation systems would reduce cost and emissions. Examples of energy storage include the Enwave Toronto District Heating system and ground source systems. Sustainability-Journal submitted that, while the OPA and IESO have plans to enter into contracts to build storage systems, the consideration of long term storage

[5] Exh L-5.4-SEC-73

options has been limited. Sustainability-Journal argued that OPG and other organizations regulated by the Board, should be required to produce public reports that consider energy storage options.

OPG replied that it does not have the type of energy storage facilities described by Sustainability-Journal and has no plans to build such facilities. Its view was that it is not necessary for OPG to produce reports on the matter.

Board Findings

The Board will not direct OPG to undertake a study of energy storage facilities and opportunities as described by Sustainability-Journal. OPG has indicated it does not intend to pursue such projects, and therefore, the further study of energy storage would not be a wise use of ratepayer money. The government's Long-Term Energy Plan discusses energy storage technologies. The Board will not prescribe a role for OPG in developing those technologies; however, the Board encourages OPG to keep abreast of new technologies in energy storage.

2.2 Hydroelectric OM&A and Benchmarking
(Issues 6.1 and 6.2)

OPG seeks approval of operating costs of $494.7M in 2014 and $503M in 2015 for the previously regulated hydroelectric facilities. OPG seeks approval of operating costs of $372.9M in 2014 and $378M in 2015 for the newly regulated hydroelectric facilities.

Hydroelectric facility operating costs include OM&A costs, an allocation of corporate support and centrally held OM&A, gross revenue charges (taxes and water rental component governed by legislation), and depreciation and taxes. This section of the Decision addresses hydroelectric OM&A and benchmarking. The other components of hydroelectric operating costs are discussed later in this Decision.

OPG's historical and forecast OM&A for the previously regulated hydroelectric facilities are summarized below.

Table 5: Previously Regulated Hydroelectric OM&A

$million	2010 Plan	2010 Actual	2011 Approved	2011 Actual	2012 Approved	2012 Actual	2013 Budget	2013 Actual	2014 Plan	2015 Plan
Base	61.8	59.4	68.7	50.1	62.1	60.2	71.9	61.6	74.6	68.6
Project	5.3	5.4	9.7	6.6	10	13.6	13	14.7	13.5	17.9
SubTotal Operations	67.1	64.8	78.4	56.7	72.1	73.8	84.9	76.3	88.1	86.5
Corporate Costs	25.1	22.4	24.8	22.0	26.3	24.5	29.7	26.1	29.8	26.9
Centrally Held Costs	20.3	19.6	22.9	15.9	25.5	19.6	25.1	20.7	26.1	26.0
Asset Service Fee	2.0	2.1	2.1	1.6	2.0	1.8	1.7	1.6	1.5	1.7
SubTotal Other	47.4	44.1	49.8	39.5	53.8	45.9	56.5	48.4	57.4	54.6
Total OM&A	**114.5**	**108.9**	**128.2**	**96.2**	**125.9**	**119.7**	**141.4**	**124.7**	**145.5**	**141.1**
Exhibit N1 Update									**149.2**	**144.2**
Exhibit N2 Update									**145.1**	**140.0**
Sources: Exh F1-1-1 Table 1, Exh L-6.1-CCC-17, Exh L-1-Staff-2 Table 15, Exh N2-1-1 Attachment 5										

OPG's historical and forecast OM&A for the newly regulated hydroelectric facilities are summarized below.

Table 6: Newly Regulated Hydroelectric OM&A

$million	2010 Plan	2010 Actual	2011 Plan	2011 Actual	2012 Plan	2012 Actual	2013 Budget	2013 Actual	2014 Plan	2015 Plan
Base	93.7	100.0	103.7	106.0	108.8	102.9	113.2	103.5	113.4	113.7
Project	37.1	39.8	27.3	21.6	20.6	20.3	16.0	23.1	24.5	32.1
SubTotal Operations	130.8	139.8	131.0	127.6	129.4	123.2	129.2	126.6	137.9	145.8
Corporate Costs	N/A	31.4	N/A	32.3	N/A	36.6	38.8	35.2	42.1	39.6
Centrally Held Costs	N/A	19.0	N/A	25.1	N/A	33.1	47.2	31.8	49.6	48.7
Asset Service Fee	N/A	3.6	N/A	3.4	N/A	3.3	3.1	3.0	2.9	3.0
SubTotal Other		54.0		60.8		73.0	89.1	70.0	94.6	91.3
Total OM&A		**193.8**		**188.4**		**196.2**	**218.3**	**196.6**	**232.5**	**237.1**
Exhibit N1 Update									**239.3**	**242.6**
Exhibit N2 Update									**234.9**	**237.3**

Sources: Exh F1-1-1 Table 2, Exh L-6.1-CCC-18, Exh L-1-Staff-2 Table 16, Exh N2-1-1 Attachment 5

There were several submissions on base and project OM&A variances. Parties observed a trend of historical under-spending versus forecast but no operational repercussions as a result of the under-spending. Board staff submitted that base and project OM&A costs should be reduced by $8.2M for each test year on the basis of OPG's updated 2014 year end forecast. SEC and LPMA proposed reductions on the basis of their analysis of historical variances.

As OPG only provided an updated 2014 year end forecast for base and project OM&A, Board staff also proposed reductions of an additional $27.2M, allocated to other OM&A

costs for each test year, on the basis of over-forecasting expenses. The submissions of other parties on these costs are noted in the corporate support cost section of this Decision.

As the application is based on a forward test period, OPG submitted that consideration should be given to forecast events in the business plan for 2014 and 2015. OPG submitted that the Board staff reference to the updated 2014 year end forecast for base and project OM&A is cherry picking and that the historical under-spending means that work was reprioritized to deal with unfilled vacancies and that OPG overcame these issues with only minor impacts to the business.

Benchmarking

OPG filed reliability, cost and safety performance benchmarking for the hydroelectric business with its application. Board staff observed that OPG purchases raw databases and submitted that the benchmarking provided in the application is not done independently. OPG's witnesses stated that they have not commissioned any independent hydroelectric benchmarking and they do not have plans to do any.[6] OPG indicated that EUCG and Navigant are third parties who act independently to define, collect and verify the raw data reported by OPG, although these third parties do not produce any reports.

OPG confirmed that only base OM&A costs are benchmarked. SEC submitted the benchmarking results should be of little comfort to the Board as significant costs have been excluded from the analysis. OPG replied that some costs are excluded as the North American hydroelectric utilities that provide the data want the benchmarking data framed without corporate costs.

The Society argued that the Board does not possess the necessary expertise to make any prudent judgment on hydroelectric OM&A. In the Society's view, benchmarking has limited practical value as there are no comparable organizations with regard to scale, diversity and complexity of OPG hydroelectric operations.

Both Board staff and SEC submitted that the Board should direct OPG to conduct a fully independent and fully allocated OM&A benchmarking exercise so that there is an appropriate structure for the hydroelectric incentive regulation framework.

[6] Tr Vol 4 page 3

Board Findings

OPG has historically over-forecast hydroelectric base and project OM&A. The variance analysis of the base and project OM&A for the historical period 2010 to 2013 clearly indicates that actual spending has been consistently less than OPG had forecast. While OPG argues that the approved OM&A should be based on test period events and the business plan underpinning the application, OPG's forecasting methodology in the current proceeding is similar to that described in previous proceedings. In these prior periods, OPG has managed its hydroelectric operations with a lower than forecast base and project OM&A envelope, with only one year being a minor exception. OPG has confirmed that this trend of under-spending relative to forecast is likely to materialize in 2014 as well.[7] The pre-filed evidence and the testimony of OPG's witnesses confirm that the hydroelectric facilities have been operated safely, reliably and meet environmental standards.

When using a forward test year methodology, historical actuals are informative. In this case, the Board is influenced by OPG's consistent historic under spending but is still mindful of OPG's submissions with respect to the need for its proposed OM&A levels for the 2014 and 2015 period. In considering these factors, the Board finds that a base and project OM&A reduction of 4.2% for the regulated hydroelectric assets is appropriate. The reduction would be $9.5M in 2014 and $9.8M in 2015. As the majority of hydroelectric OM&A expense is related to compensation, this reduction to the hydroelectric OM&A budget for each of the two years will be subsumed into the disallowances for compensation discussed later in this Decision.

The Board finds the hydroelectric benchmarking to be inadequate. The analysis of externally provided OM&A, reliability and safety databases and the reporting is done by OPG, not an independent third party. Further, in the two previous cost of service applications and the current application, OPG has provided OM&A benchmarking information that only considers base OM&A which is only 50% of total OM&A expenses. The Board observes that OPG's nuclear business benchmarking is further advanced than its hydroelectric business benchmarking. The Board notes that OPG responded to Board direction from EB-2007-0905 regarding the benchmarking of the nuclear business. In 2009, ScottMadden Inc., assisted by OPG, identified key performance metrics for benchmarking and identified the peer groups for comparison. The nuclear cost benchmarking includes the allocation for corporate costs. OPG has adopted the

[7] Undertaking J3.13

ScottMadden methodology and format in full for its annual nuclear benchmarking reporting.

The Board orders OPG to have a comparable fully independent benchmarking study undertaken of the hydroelectric operations as soon as possible. The results of this study will be important in developing the incentive regulation methodology for OPG. Data used in the study should be as recent as possible (i.e. not older than 2013), without creating delays in the completion and dissemination of the study.

With respect to the Society's view that little weight should be placed on any benchmarking, the Board reminds the Society that the Act and O. Reg. 53/05 provide the Board with the authority to set payment amounts for OPG's regulated facilities. In addition the Memorandum of Agreement between OPG and the Shareholder requires that OPG's regulated assets be subject to public review and assessment by the Board. The Memorandum of Agreement also requires OPG to establish operating and financial results and measures that will be benchmarked against the performance of the top quartile of electricity generating companies in North America.

2.3 Hydroelectric Capital Expenditure and Rate Base

(Issues 2.1, 4.1, 4.2 and 4.3)

OPG seeks Board review of the capital expenditures proposed for 2014 and 2015. These capital expenditures have no impact on the payment amounts for 2014 and 2015 unless the projects are completed and go into service during this period. Board acceptance of the budget does however provide guidance to OPG with respect to the reasonableness of the budget.

OPG's historical and forecast capital expenditures for the previously regulated and newly regulated hydroelectric facilities are summarized below.

Table 7: Hydroelectric Capital Expenditures (excluding Niagara Tunnel)

$millions	2010 Budget	2010 Actual	2011 Approved	2011 Actual	2012 Approved	2012 Actual	2013 Budget	2013 Actual	2014 Plan	2015 Plan
Niagara Plant Group	36.2	28.5	30.7	27.2	30.9	27.1	28.8	20.9	24.8	34.3
Saunders GS	17.3	11.8	9.2	8.1	5.9	2.7	5.0	5.8	9.7	3.9
Newly Regulated *	80.2	68.6	76.7	61.4	91.4	80.1	71.4	60.5	91.0	100.0
Total	**133.7**	**108.9**	**116.6**	**96.7**	**128.2**	**109.9**	**105.2**	**87.2**	**125.5**	**138.2**

Source: Exh D1-1-1 table 2 and Exh L-1-Staff-2 Attachment 1 Table 8

* Note: Amounts for Newly Regulated shown under the Board Approved columns are OPG Budget amounts.

Board staff submitted that a $38M reduction to test period capital was appropriate on the basis of the regulatory delays and economic considerations for the Ranney Falls project. Board staff noted that this reduction would not impact rate base since the planned in-service date is after the test period. OPG replied that there is nothing to suggest that regulatory approvals will not be forthcoming for the Ranney Falls project.

To assess whether test period capital expenditure was reasonable, AMPCO analyzed historical expenditures and determined that for the period 2010 to 2013, OPG spent 81% of the previously regulated hydroelectric facilities budget and 85% of the newly regulated hydroelectric facilities budget. On this basis, AMPCO proposed that reductions to the proposed hydroelectric capital expenditures in the test period in the amount of $43.4M were appropriate. OPG argued that applying historical variances to the test period ignores the evidence filed in support of capital spending in the test period.

OPG is also seeking approval of regulated hydroelectric in-service additions to rate base of $119.9M, $86.1M and $151.6M for 2013, 2014 and 2015, respectively. OPG's historical and proposed rate base for the test period is set out in the following table.

Table 8: Hydroelectric Rate Base

$millions	2010 Budget	2010 Actual	2011 Approved	2011 Actual	2012 Approved	2012 Actual	2013 Budget	2013 Actual	2014 Plan	2015 Plan
Niagara Plant Group excluding NTP	2,489.7	2,452.5	2,482.5	2,437.1	2,474.3	2,422.0	2,405.0	2,404.6	2,391.4	2,378.1
Niagara Tunnel	-	18.3	-	18.1	-	17.8	1,143.6	1,140.4	1,473.6	1,457.7
Saunders GS	1,301.7	1,300.1	1,298.8	1,294.4	1,291.0	1,281.7	1,260.5	1,261.3	1,240.5	1,226.4
NPG Cash Working Capital	23.6	26.4	21.5	21.5	21.5	21.7	21.7	21.7	21.7	21.7
NGP Materials & Supplies	0.7	0.7	0.6	0.8	0.6	0.8	0.7	0.5	0.7	0.7
Newly Regulated *							2,507.0	2,518.4	2,502.6	2,519.2
Newly Reg. Cash Working Capital *							0.7	8.3	8.3	8.3
Newly Reg. Materials & Supplies *							8.3	0.6	0.7	0.7
Total	**3,815.7**	**3,798.0**	**3,803.4**	**3,771.9**	**3,787.4**	**3,744.0**	**7,347.5**	**7,355.8**	**7,639.5**	**7,612.8**

Source: Exh B1-1-1 Table 1 and Exh B2-2-1 Table 1 and Exh L-1-Staff-2 Attachment 1 Table 2

* Note: Amounts for Newly Regulated shown for 2013 are for illustrative purposes.

Based on Board staff's analysis of historical in-service additions for projects greater than $5M, staff observed the forecast additions were generally overstated in the period 2010 to 2013 and proposed a $13M per year reduction for the test period.

SEC reviewed in-service additions for the previously regulated hydroelectric facilities and determined that in aggregate 72.8% of forecast was placed in-service. The following table was filed in the SEC submission.

Table 9

In-Service Capital Additions (excluding NTP) ($M)					
	2010	**2011**	**2012**	**2013**	**Average**
Previously Regulated Plan	60.9	42.9	51.5	44.3	49.9
Previously Regulated Actual	20.0	63.5	15.5	46.4	36.4
Variance (%)	***32.8%***	***148.0%***	***30.1%***	***104.7%***	*72.8%*
Source: D1/1/2/Table 5. L/1.0/Sch 1 Staff-002/Attach 1/Table 2 (2013 Actuals).					

On the basis of SEC's analysis, LPMA proposed that the Board approve 72.8% of the proposed rate base additions for the test period. SEC's analysis of historical capital expenditure for both the previously and newly regulated hydroelectric facilities indicated that 83.3% of plan went into service. SEC proposed that the Board approve 83.3% of the proposed rate base additions for the test period.

Project delays can contribute to in-service addition variances; however, OPG pointed out that there is a cyclical pattern to the variances for the previously regulated hydroelectric facilities. OPG stated that the 2013 variance is minor and an indication of improved forecasting. Further, the major drivers of variances are projects subject to section 6(2)4 of O. Reg. 53/05 which provides for the recording of variances between actual and forecast costs, and are addressed by the capacity refurbishment variance account.

Board Findings

The Board finds that the hydroelectric capital budget for projects coming into service during the test period is reasonable. The projects are supported by business cases approved by the appropriate level of authority within OPG. The Board is providing no explicit approval in this Decision for the capital budget associated with multi-year hydroelectric projects which do not come into service during the test period. As a result, the Board will not reduce OPG's capital budget based on historic budgets exceeding actual expenditures as proposed by certain intervenors and Board staff. The Board is satisfied with OPG's evidence regarding the delays in prior projects to explain historical under spending.

Regarding OPG's proposed in-service capital additions, the evidence indicates no clear pattern of historical variances which can be used to predict actual rate base additions for 2014 and 2015. OPG failed to meet its in-service capital addition budget (or approved level) for its previously regulated hydroelectric facilities in 2010 and 2012, however the budget was exceeded in 2011 and 2013. In the case of additions being lower than budgeted, OPG's witnesses testified that issues arose on specific projects that led to in-service date delays beyond the year in which they were proposed to be in-service. The Board notes that in years in which capital additions exceeded the budget, the amount of overage was much less than the years when the capital additions were below the budgeted level. Over the four year period (2010 to 2013) SEC put forward that the average capital additions were only about 73% of the planned in-service additions.

The Board finds that some level of reduction to the in-service capital additions is required. OPG has not satisfied the Board that it will meet its in-service capital addition budget for 2014 and 2015. Rather than the $13M reduction per year suggested by Board staff, the 17% reduction suggested by SEC or the 27% reduction proposed by LPMA (the latter both based on the four year average additions variance), the Board finds it appropriate to reduce the capital in-service additions by 10% in 2014 and 2015. This amount represents a relatively minor reduction but reflects the fact that the Board is not satisfied by the evidence provided that there will not be in-service delays in 2014 and 2015. The capital additions approved by the Board are therefore $119.9 M in 2013 (actuals), $77.5M in 2014 and $136.4M in 2015.

2.4 Niagara Tunnel Project

(Issues 4.4 and 4.5)

The Niagara Tunnel Project is a 10.2 km long tunnel constructed by OPG with a diameter of 12.7 metres which runs under the City of Niagara Falls. Its purpose is to increase the flow of water to the Niagara plant group, and thereby increase generation by 1.6 TWh annually. After several years of construction, the asset was placed in service in March 2013 at a cost about 50% greater than originally budgeted.

In this application, OPG is seeking the Board's approval to close $1,452.6M in capital expenditures (in-service) (see line 5 of Table 10) to the test period rate base. OPG states that the cost above the original budget arose entirely from the fact that the rock conditions encountered during construction were worse than OPG reasonably anticipated.[8]

The Board's consideration of the costs of the Niagara Tunnel Project is guided by section 6(2)4 of O. Reg. 53/05, which states:

> The Board shall ensure that Ontario Power Generation Inc. recovers capital and non-capital costs, and firm financial commitments incurred to increase the output of, refurbish or add operating capacity to a generation facility referred to in section 2, including, but not limited to, assessment costs and pre-engineering costs and commitments,
>
> i. if the costs and financial commitments were within the project budgets approved for that purpose by the board of directors of Ontario Power Generation Inc. before the making of the Board's first order under section 78.1 of the Act in respect of Ontario Power Generation Inc., or
> ii. if the costs and financial commitments were not approved by the board of directors of Ontario Power Generation Inc. before the making of the Board's first order under section 78.1 of the Act in respect of Ontario Power Generation Inc., if the Board is satisfied that the costs were prudently incurred and that the financial commitments were prudently made.

The OPG Board of Directors approved the expense of $985.2M in 2005, prior to the Board's first order in 2008. OPG states that the issue before the Board is whether the $491.4M in expense beyond the $985.2M was prudently incurred. None of the parties have disputed this assertion.

The PWU submitted that the geological investigations and studies undertaken were appropriate and that OPG's conduct during and after the differing subsurface condition dispute was appropriate. PWU states the $491M additional cost was incurred reasonably and prudently. However, a number of parties found fault with OPG's management of the Niagara Tunnel Project, and argued for a range of disallowances to the amount closing to rate base.

Background

The initial budget for the project approved by OPG's Board of Directors in 2005 was $985.2M. There were a number of delays and cost over-runs resulting from

[8] Argument-in-Chief page 23

unanticipated subsurface conditions. Ultimately the total cost of the Niagara Tunnel Project was $1,476.6M of which OPG is seeking to close $1,452.6M to rate base in this application.[9] A summary of project costs is provided in the table below.

Table 10: Niagara Tunnel Project

	$ millions*	Pre- 2008 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Test Year	2015 Test Year	Total
1	Budget Approved/Revised by OPG Board	985.0	985.0	1,600.0	1,600.0	1,600.0	1,600.0	1,600.0	1,600.0	1,600.0	
2	Capital Expenditures	300.2	131.3	213.5	231.8	264.2	231.2	86.6	13.0	0.4	
3	Accumulated Capital Expenditures	300.2	431.5	645.0	876.8	1,141.0	1,372.2	1,458.8	1,471.8	1,472.2	
4	Gross Plant in-service (Opening Balance)	19.2	19.2	19.2	19.2	19.2	19.2	19.2	1,458.4	1,471.4	
5	Gross Plant additions	-	-	-	-	-	-	1,439.2	13.0	0.4	1,452.6
6	Gross Plant in-service (Closing Balance) **	-	-	-	-	-	-	1,458.4	1,471.4	1,471.8	

Source: OPG Reply Argument p.26 & Exh L-4.5-Staff-25

*Numbers may not add up due to rounding

** To calculate the total cost of the Niagara Tunnel Project, $4.6M in removal costs (treated as operating expenses) is added to the $1,472.2M in total capital(in-service) expenditures. This results in a Niagara Tunnel Project total cost of **$1,476.6M**. The $4.6 M is recorded in the Capacity Refurbishment Variance Account.

OPG's preparatory geotechnical investigation for a Niagara Tunnel began in 1983. The tunnel passes through geologically challenging conditions, including the Queenston shale formation. OPG's initial investigations included 59 boreholes and an exploratory adit (a test tunnel).

OPG undertook a request for proposal process in 2004/2005. The request for proposal mandated a tunnel boring process, which was a requirement of the environmental assessment. The request for proposal was based on OPG's geotechnical investigations and OPG's risk assessment analysis. Strabag AG of Austria and its wholly owned subsidiary Strabag Inc. ("Strabag") were the successful bidders.

Strabag's bid was based on a "design-build" approach, whereby OPG would hire a single firm (i.e. Strabag) to design and build the project to OPG's pre-established specifications.[10] The OPG Board of Directors approved the release of $985.2M, of which $112M was contingency. The business case presented to the OPG Board of Directors stated that the project economics compared favourably against other renewable generation options. The Design Build Agreement with Strabag was signed in August 2005. The new tunnel was projected to be in service by June 2010 and was

[9] The $24M difference is comprised of amounts added to rate base prior to 2008 and an amount attributed to OM&A.
[10] The other common approach is design-bid-build, whereby OPG would hire a firm to design the tunnel, issue a request for proposal on the basis of the design, and then select a firm to construct it.

expected to increase generation by 1.6 TWh. The initial cost of the tunnel itself, as reflected in the Design Build Agreement, was $622.6M to be paid to Strabag.

The terms of the Design Build Agreement were based in part on a Geotechnical Baseline Report. The purpose of the Geotechnical Baseline Report was to establish a contractual baseline for subsurface hydro-geological conditions. Initially OPG prepared a geotechnical baseline report which was included with the request for proposal and bidders including Strabag provided geotechnical baseline reports (based on OPG's report) with their bids – these are referred to in the evidence as Report A and Report B respectively. The final Geotechnical Baseline Report (sometimes referred to in the evidence as Report C) was negotiated jointly by OPG and Strabag as part of the Design Build Agreement. Unless otherwise specified, references to the Geotechnical Baseline Report in this Decision refer to this final Report C.

In the event that the actual subsurface conditions were found to be materially different from the conditions anticipated in the Geotechnical Baseline Report, the Design Build Agreement provided a number of potential remedies. If OPG agreed that there was a "differing subsurface condition", the parties could negotiate changes to the schedule and price. If OPG did not agree that there was a differing subsurface condition, the Design Build Agreement outlined a dispute resolution process, which included recourse to a third party Dispute Review Board.[11]

One of the subsurface issues addressed in the Geotechnical Baseline Report was "overbreak". Overbreak is the cracking and loosening of rocks above the tunnel boring machine[12] as it moves through the rock to create the tunnel. It was recognized by both OPG and Strabag that overbreak could be an issue, particularly in the Queenston shale formation through which portions of the tunnel were expected to pass. OPG's original assessment was that there would be approximately 45,000 m^3 of overbreak, whereas Strabag estimated only 15,000 m^3. In the final Geotechnical Baseline Report (which was part of the Design Build Agreement), the parties agreed to a figure of 30,000 m^3.

Construction began in September 2005. Excavation by the open tunnel boring machine commenced in September 2006. Starting in spring 2007, significant quantities of overbreak were reported, which resulted in delay and additional expense to Strabag. Strabag considered this excessive overbreak to be due to a differing subsurface

[11] Exh D1-2-1 Attachment 6, Design Build Agreement, sections 5.5-5.7.
[12] Exh D1-2-1 page 72

condition more significant than had been previously identified, and attempted to negotiate changes to the Design Build Agreement with OPG. By February 2008, it was clear that the parties would be unable to resolve the issue on their own, and the dispute was referred to a Dispute Review Board.

Strabag argued before the Dispute Review Board that one or more differing subsurface conditions existed based on five issues of dispute, including the excessive amount of overbreak. OPG's position was that no differing subsurface condition existed and that Strabag was at fault for the overbreak because it substantially modified its tunnel boring machine design and rock support from the original proposal.

The Dispute Review Board held that for three of the issues identified (large block failures, insufficient "stand-up" time, and an issue related to tunneling under the buried St. Davids Gorge) there was no differing subsurface condition. For the other two issues (excessive overbreak and the table of rock conditions and rock characteristics) the Dispute Review Board found that there was a differing subsurface condition. With respect to the differing subsurface conditions, the Dispute Review Board report stated:

> Since the development of the [Geotechnical Baseline Report] was the mutual responsibility of both Parties, we recommend that the Parties negotiate a reasonable resolution based on a fair and equitable sharing of the cost and time impacts resulting from the overbreak conditions that have been encountered and the support measures that have been employed. [13]

Following negotiation, OPG agreed to pay Strabag an extra $40M to resolve all issues to November 30, 2008 (Strabag had claimed additional costs of $90M). After considering several options, OPG determined that the best way to ensure the completion of the Project was to renegotiate the Design Build Agreement. The excessive amount of overbreak required tunnel profile restoration (infill to restore tunnel profile to a circular shape), realignment of the tunnel route, and additional cost and time. An Amended Design Build Agreement, based on target cost instead of fixed price, was approved by the OPG Board of Directors in May 2009. The total project cost estimate was revised to $1.6 billion, of which $985M was now allocated to Strabag for constructing the tunnel. The Amended Design Build Agreement moved the completion date for the project from June 2010 to June 2013. The supporting business case stated

[13] Exh D1-2-1 Attachment 7 page 18

that completing the tunnel was still economic when compared with alternative energy supply options.

Ultimately the tunnel was completed in March 2013, for less than the $1.6 billion revised cost. The final total cost for the Niagara Tunnel Project was $1,476.6M (see footnote to Table 10). Strabag earned a number of incentives for completing the project ahead of the revised schedule and for less than the revised budget.

As part of its application, OPG filed a report by Mr. Roger Ilsley, a geotechnical and tunnel expert. The report concluded that OPG's site investigations were appropriate and completed to professional standards. Similarly Strabag's design work was completed to professional standards.[14] Mr. Ilsley also appeared as a witness at the oral hearing.

Geotechnical Baseline Report

The submissions of Board staff, AMPCO, CME and SEC criticized the Geotechnical Baseline Report. OPG was solely responsible for the initial Report A which was the basis for the request for proposal and subsequent reports. The bidders provided Report B, a supplemented version of Report A, with their bids. The final Report C was agreed to by OPG and the successful bidder, Strabag. It was submitted that the contractually binding Report C was ambiguous and not in compliance with the *Geotechnical Baseline Reports for Construction – Suggested Guidelines*. AMPCO submitted that the ambiguity in the original Report A misled Strabag to propose open tunnel boring instead of closed tunnel boring and that OPG's expert, Mr. Ilsley, agreed in cross examination that Report C was ambiguous.[15]

As summarized in the Dispute Review Board's report:

> The [Dispute Review Board] agrees that the Table of Rock Conditions and Rock Characteristics is inadequate to be used for the identification of [Differing Subsurface Conditions] and, further, that the inclusion of such terms as the "closest match" and "all other conditions" essentially renders the concept of [Differing Subsurface Conditions] meaningless and makes the [Geotechnical Baseline Report] defective.[16]

[14] Exh F5-6-1
[15] Tr Vol 2 page 53
[16] Exh D1-2-1 Attachment 7 page 18

OPG spent $57M on geotechnical investigations. OPG asserts that this was a considerable amount of investigation, and the results were unchallenged by five contractors who did not seek additional geotechnical data to submit their bids. Further, the geotechnical investigation and results were supported by Mr. Ilsley. The guidelines for geotechnical baseline reports recognize that it is not always possible to describe geologic conditions precisely. OPG stated that AMPCO's criticism that the geotechnical baseline report was misleading to bidders is incorrect as Strabag considered both closed and open tunnel boring.

In OPG`s view, the parties have not pointed to a single action that OPG took that was unreasonable in developing the Geotechnical Baseline Report.

Risk Management

The submissions of Board staff, AMPCO and SEC find fault with OPG's risk assessment process and the risk OPG assumed in the project. Some parties noted that OPG's contracting approach was a risk since tunnels in North America have traditionally been constructed using Design-Bid-Build contracts instead of Design Build. SEC observed that of the 59 borehole tests conducted, only 20 were located along the proposed route. SEC also questioned OPG's decision to rely on 1993 borehole data as testing methods and instrumentation had likely improved in the interim.

In OPG`s view the Design Build approach was selected to appropriately allocate project risk and to obtain as much upfront price certainty as possible. OPG stated that the criticisms of the vintage of borehole data are contrary to the evidence of Mr. Ilsley, who testified that while the electronic methods to record geotechnical results have improved, the tests themselves are unchanged.

OPG submitted that all the project risks identified by OPG were mitigated to low risk except subsurface conditions which remained at medium risk. OPG`s mitigation activity to move the risk from high to medium was the extensive field investigation over 10 years, the 3 stage geotechnical baseline report process and contingency for the tunneling work. While total project contingency was $112M, the contingency for the tunneling portion of the project was $96M. OPG stated that to mitigate to low risk would be costly. As OPG assumed full responsibility for geological conditions in design build, the parties submitted that OPG assumed too high a risk.

OPG replied that, "While it is clear in hindsight that OPG underestimated the potential severity of the rock conditions encountered, particularly the nature and extent of the overbreak, this occurred because the rock conditions were much more challenging than OPG, its experts and Strabag expected based on extensive geotechnical sampling and analysis, and not because OPG's risk identification and quantification efforts were deficient."[17]

Contract Renegotiation

Several parties submitted that OPG was not prudent in its renegotiations with Strabag and that the Amended Design Build Agreement did not reflect sharing of responsibility for losses as determined by the Dispute Review Board. SEC observed that few options were presented to the OPG Board of Directors and that the Amended Design Build Agreement was for all intents and purposes final when it was presented to the OPG Board.

When Strabag filed its claim for $90M, tunneling had advanced to the 3 km point. OPG had paid Strabag $40M, or $13.3M/km. CME observed that the Amended Design Build Agreement provided for an additional $243M for the remaining 7 km, or $34.7M/km. CME submitted that OPG should not have paid Strabag more than $13.3M/km for the remaining 7 km, and that the difference would result in a $149M disallowance.

A number of parties submitted that OPG could have achieved a better result through the Amended Design Build Agreement. OPG stated that the understanding of the parties with respect to sharing of risk is incorrect. At the end of three years of work, Strabag had a loss of $90M, which was settled by a $40M payment. Strabag finished the tunnel with what OPG characterized as a very small profit after an additional four years of work. OPG argued that CME`s understanding of additional costs per km are incorrect as the $90M claim did not include tunnel profile restoration, which had to be undertaken in addition to completion of the remaining 7 km.

OPG also argued that there would have been significant costs for terminating the Strabag contract. Mr. Ilsley referred to the Seymour-Capilano project in Vancouver which was rebid at 1.8 times the original cost for the remaining 40% of the work with potential litigation by the original contractor.[18]

[17] Reply Argument page 52
[18] Tr Vol 1 page 80

Disallowances Proposed by Parties

Board staff and the parties have proposed reductions to the rate base addition ranging from $50M to $407.4M:

- Energy Probe submitted that a $50M rate base addition reduction was appropriate as OPG's use of the design build model limited its ability to terminate Strabag.
- Board staff listed 7 items to deduct from rate base additions totaling $105M, including the $40M paid to Strabag pursuant to its claim, design costs, overhead costs and carrying charges.
- In addition to $149M related to contract renegotiation, CME agreed with several of the items that Board staff proposed for disallowance, and proposed a $208.5M total disallowance.
- SEC proposed that rate base additions should be reduced by $245.7M, i.e. half of the amount in excess of the originally approved $985.2M
- AMPCO's submission listed 9 items, including the entire diversion tunnel expense beyond the original estimate of $280.3M and $10.8M paid to OPG's representative, Hatch. AMPCO submitted that $407.4M should be removed from OPG's proposed rate base additions.

OPG replied that all of these disallowances should be rejected, and that the analysis of Board staff and parties is inadequate. Other than Mr. Ilsley, there were no expert witnesses that gave evidence related to the Niagara Tunnel. OPG argued that the parties did not fully understand the evidence and the arguments are selective reviews based on hindsight. Although the parties claimed imprudence, in OPG's view the parties failed to identify a single action that OPG took or failed to take that was unreasonable at the time.

OPG stated that the Niagara Tunnel Project costs are reasonable and that "if the rock conditions had been known in advance with perfect foresight, the tunnel would have cost at least what OPG paid and may have cost more."[19]

[19] Reply Argument page 39

Board Findings

The Board finds that $1,364.6M in Niagara Tunnel Project capital expenditures (in-service) should close to rate base in the test period. This represents a disallowance of $88.0M (or approximately 6%) from the $1,452.6M proposed by OPG. The disallowances are based primarily on OPG's response to the Dispute Review Board's decision and recommendations, in particular OPG's decision to pay $40M for claims prior to December 2008, and the terms negotiated with Strabag in the Amended Design Build Agreement.

The Board accepts OPG's argument that the Board's review of the Niagara Tunnel Project is a "prudence review", and that the Board is not permitted to use hindsight when considering OPG's actions. The Board also accepts OPG's assertion that, pursuant to section 6(2)4 of O. Reg. 53/05, only the $491.4M in expenses incurred after 2008 are subject to review. As a result, the Board will not opine on the actions of OPG prior to the commencement of the Board's regulation of OPG in 2008.

Settlement of Strabag's $90M Claim

In its report, the Dispute Review Board recommended "that the Parties negotiate a reasonable resolution based on a fair and equitable sharing of the cost and time impacts resulting from the overbreak conditions that have been encountered and the support measures that have been employed. Both Parties must accept responsibility for some portion of the additional cost, but at the same time the Contractor must have adequate incentives to complete the Work as soon as possible."[20]

Based in part on this recommendation, OPG decided on two courses of action. First, it agreed to settle all of Strabag's pre-December 2008 claims for $40M (Strabag had claimed $90M). Second, OPG determined that the best solution moving forward was to renegotiate the Design Build Agreement with Strabag. The resulting Amended Design Build Agreement target cost was $985M plus incentives (compared with the Design Build Agreement contract cost of $622.6M).

The Project was completed pursuant to the terms of the Amended Design Build Agreement. Strabag earned the incentives described in the Amended Design Build

[20] Exh D1-2-1 Attachment 7 pages 18-19

Agreement. Overall OPG estimates that Strabag earned a profit of approximately $26M on the Project as a whole.[21]

Several parties questioned whether the Amended Design Build Agreement appropriately allocated responsibility for the additional costs between OPG and Strabag. OPG's witnesses testified that absent a successfully renegotiated Design Build Agreement, Strabag would have likely walked away from the Project. OPG would then have been forced to find a new contractor to complete the Project. OPG expected that the costs of finding a new contractor at that stage of the Project would have greatly exceeded the cost of renegotiating the Design Build Agreement with Strabag.

The Board is not satisfied that paying Strabag $40M for its claims up to December 2008 was prudent. This Board finds that the non-binding recommendations of the Dispute Review Board were reasonable, and that some level of shared responsibility between OPG and Strabag was appropriate. However, paying a $40M settlement (44% of Strabag's $90M claim) is excessive in the Board's view. There were five issues of dispute that were referred to the Dispute Review Board. The Dispute Review Board found that OPG was not responsible for three of the five issues and that OPG had only joint responsibility for the remaining two issues. No evidence was filed on the relative value or cost of the five issues. OPG's witnesses testified that the individual issues were not quantified.

As a result of the contract renegotiation with Strabag, OPG had the right to audit Strabag's claimed losses of $90M. To the extent that the $90M was not substantiated in the audit, the $40M payment could be reduced proportionately. OPG's witnesses testified that OPG's internal auditors conducted the audit and found that a total of $12.6M was not associated with legitimate expenses, resulting in a loss of only $77.4M.[22] The auditors did not recognize inter-company transfers within Strabag's organization, thereby reducing the amount from $90M to $77.4M.[23] OPG's evidence was that they could reduce the $40M settlement proportionately based on the audit, but did not do so.[24]

The Board is unable to find that a $40M settlement of Strabag's claim was prudently incurred. In the absence of information regarding the costs attributable to each of the

[21] Tr Vol 2 page 124
[22] Exh L-4.5-SEC-41 Attachment 16
[23] Tr Vol 2 page 149
[24] Exh D1-2-1 page 106

five issues, the Board must use its judgment of what is a reasonable amount. In determining the amount, the Board has decided to utilize the findings of the Dispute Review Board. As a result, the Board finds that OPG's ratepayers should not pay any amount for the three issues which OPG was not responsible, but should pay 50% of two issues for which OPG was jointly responsible. In addition, the Board is persuaded by the results of OPG's audit and considers the $77.4M to be the appropriate starting point for the Board's calculation, not the $90M claim by Strabag. There was no evidence or testimony provided supporting Strabag's claimed amount. As a result, the Board finds that ratepayers should only pay 20% of the $77.4M audited amount, or $15.5M. In addition, the Board denies the associated carrying costs of the disallowed $24.5M,[25] which results in a reduction of another $3.5M.[26] The Board finds this disallowance of $28.0M reasonable given the evidence provided.

Terms of the Amended Design Build Agreement

The Board finds that not all of the costs associated with the Amended Design Build Agreement should be passed on to ratepayers.

The Board accepts that absent a revised Design Build Agreement, there was a possibility that Strabag would have abandoned the Project. Had that occurred, the cost of completing the Project with a new contractor might well have exceeded the costs of the Amended Design Build Agreement. In the Board's view, however, the possibility of project abandonment and the speculation of the financial impact of this does not justify the level of incentives offered to Strabag in the Amended Design Build Agreement. The question is not: Would it have cost OPG more had Strabag walked away? Instead, the salient question is: Could OPG have achieved better terms than it did in negotiating with Strabag to move forward after the Dispute Review Board findings?

The risk of the contractor abandoning the Project was recognized in the original 2005 Business Case. The project risk profile identified this risk as "medium" before mitigation, and "low" after mitigation. The mitigation activity described in the project risk profile was a requirement for the contractor to provide bonds and/or letters of credit as security, and to provide a parental guarantee. As part of the Design Build Agreement, Strabag was required to post a letter of credit for $70M, and provide a parental indemnity guaranteeing Strabag's performance of the contract and indemnifying OPG

[25] $40M – (20% x $77.4M)
[26] $24.5M x 5.25% x 33/12 months

for any damages resulting from a breach by Strabag.[27] The Indemnity Agreement provided that Strabag's parent company "irrevocably and unconditionally agrees to indemnify and save harmless OPG from and against all costs, damages, expenses, losses, liabilities, demands, claims, suits, actions, proceedings, judgments and obligations (including, without limitation, legal fees and expenses) arising in respect of any breach" of the Design Build Agreement. The Indemnity Agreement further allowed OPG to make credit inquiries about the parent company, and provided OPG with three years of financial statements.[28]

OPG's witnesses further confirmed that Strabag would suffer serious repercussions were it to walk away from the Project, including being sued by OPG for breach of contract, and suffering a serious blemish on its business reputation.[29]

Strabag, therefore, had very strong incentives to reach an agreement with OPG to find a way to complete the Project. Walking away from the Project would have been an extremely expensive and unpalatable option for Strabag, and for its parent company.

Under these circumstances, the Board finds that the incentives offered to Strabag through the Amended Design Build Agreement were excessive. OPG understood that a contractor default was a potential risk, and indeed it took steps that should have mitigated that risk through a letter of credit and a comprehensive parental indemnity. However, when it came time to renegotiate the Design Build Agreement, OPG did not properly use its leverage to secure a more favourable deal. The Board will disallow recovery of $60M.[30] The Board is mindful of the Dispute Review Board's recommendation that Strabag have appropriate incentives to complete the work. However, in the Board's view the Amended Design Build Agreement provided adequate "incentive" even without the specific incentive clauses. OPG agreed to pay Strabag hundreds of millions of extra dollars more than was provided for in the original Design Build Agreement. In the Board's judgment, the provision for incentives above this was not necessary and not prudent.

The total disallowance related to the capital expenditures of the Niagara Tunnel Project is $88.0M, which the Board finds to be imprudently incurred. The Board approves

[27] Exh D1-2-1 page 37
[28] Indemnity Agreement – Appendix 4.1(e) to the Design Build Agreement.
[29] Tr Vol 2 pages 122-123
[30] Exh D1-2-1 Attachment 9 - $40M schedule and cost performance incentive, $10M interim completion fee, and $10M substantial completion fee

$1,364.6M as the amount of Niagara Tunnel Project capital expenditures (in-service) to close to rate base in the test period.

2.5 Hydroelectric Other Revenue

(Issue 7.1)

OPG earns revenue from a number of sources other than through the regulated payment amounts for hydroelectric generation. These sources of other revenue include ancillary services, segregated mode of operations and water transactions.

The historical and forecast other revenues for the previously regulated and newly regulated hydroelectric facilities are summarized in the following table.

Table 11: Hydroelectric Other Revenue

$million	2010 Actual	2011 Actual	2012 Actual	2013 Budget	2013 Actual	2014 Plan	2015 Plan
Previously Regulated Ancillary Services	26.2	22.2	20.8	17.8	37.1	18.1	18.5
Seg Mode of Operation	-0.9	1.7	-0.8	1.6	4.1	0.0	0.0
Water Transactions	5.5	7.5	1.6	6.0	1.0	1.7	1.7
HIM Adjustment				6.5	6.5		
Total	**30.8**	**31.4**	**21.6**	**31.9**	**48.7**	**19.8**	**20.2**
Total: Exhibit N1 Update (Ancillary Services: $32.2M - 2014, $32.9M - 2015)						**33.9**	**34.6**
Newly Regulated Ancillary Services	**26.4**	**26.1**	**25.9**	**22.2**	**35.7**	**22.7**	**23.1**
Source: Exh G1-1-1, Exh L-1-Staff-2, Exh N1-1-1							

The IESO purchases the following ancillary services from OPG: black start capability, reactive support/voltage control service, automatic generation control and operating reserve. A forecast of the revenues from ancillary services is applied as an offset to the hydroelectric revenue requirement. Differences between the forecast and actual revenues are recorded in the Ancillary Services Net Revenue Variance Account – Hydroelectric. OPG has proposed that the account also apply to the newly regulated hydroelectric facilities.

The Exhibit N1 update is the result of higher forecast revenue for operating reserve and a new contract for regulation service, resulting in an increase in ancillary services revenue forecast for the previously regulated hydroelectric facilities of $14.1M in 2014 and $14.4M in 2015.

In the current application OPG has applied an escalation factor of 2% to the 2013 ancillary services budget amount to determine the forecast for 2014, which was escalated to determine the 2015 forecast. Both AMPCO and LPMA submitted that the forecast should be based on 2013 actuals and then escalated as proposed by OPG. CME submitted that the forecast should be based on the average of 2011-2013 actuals and then escalated as proposed by OPG. In response, OPG stated that some of the services are market based and some are contractual, and that forecasting requires more rigor than reference to historical values.

Segregated mode of operation transactions occur at the Saunders GS. Units at Saunders can be segregated, when pre-arranged, to serve the Hydro Quebec control area. OPG has forecast revenue from segregated mode of operation on the basis of a three year rolling average (2010-2012). AMPCO, CME and LPMA have proposed test period forecasts based on a three year rolling average that includes 2013 actuals. OPG argued that these submissions are opportunistic and would not have been made if the 2013 actuals reduced the average.

Water transactions between OPG and the New York Power Authority allow the two parties to use a portion of the other's share of water for electricity generation. In the previous proceedings, water transaction forecasts were based on the average of the three historical years. In the current application, water transaction volumes are forecast to decrease by 65% due to the diversion capability of the Niagara Tunnel which went into service in March 2013. OPG's forecast is based on the 2010-2012 average actual water transactions reduced by 65%. CME submitted that the forecast should be based on 2011-2013 average actuals.

Board staff observed that the historical other revenue variances were mainly due to ancillary services, for which there is a variance account. Board staff submitted that the proposed hydroelectric other revenues were appropriate.

Board Findings

The Board accepts the Exhibit N1 forecast revenues of $32.2M in 2014 as a result of ancillary services from previously regulated assets and $22.7M from the newly regulated assets, and $32.9M and $23.1M respectively in 2015 for these assets. The Board notes that the Ancillary Services Net Revenue Variance Account will continue throughout this period, accounting for any changes in revenues from the activities.

With respect to revenues from Segregated Mode of Operation, the Board will continue with the methodology established by the Board in EB-2007-0905 which uses a three-year historical average for the forecasting of 2014 and 2015. However, the Board will use the most recent historical actuals in calculating this average, thus the three years will be 2011, 2012 and 2013. This results in net revenue of $1.7M from segregated mode of operation for each of 2014 and 2015.

For net revenue from water transactions the Board accepts a departure from the methodology approved by the Board in EB-2007-0905 and EB-2010-0008, as the evidence is compelling that water transactions will be decreased as a result of the Niagara Tunnel being in-service. Similar to the determination of the segregated mode of operation forecast, the Board will use the most recent historical actuals for 2011, 2012 and 2013. As the Niagara Tunnel came into service in March of 2013, the 65% reduction is only applied to one quarter of the 2013 water transaction revenue. Hydroelectric Other Revenue of $1.3M related to water transactions will be included in each of 2014 and 2015. Once further actual data is available with the Niagara Tunnel in-service, this reduction by 65% should prove to be unnecessary and the previous methodology of the three year historical average may again be applicable.

As per the Board’s findings in this Decision with respect to a revised methodology for the hydroelectric incentive mechanism, additional other revenues of $39M and $48M shall be appropriately allocated by OPG between the previously and newly regulated hydroelectric facilities and included in the revenue requirement determination for 2014 and 2015.

3 NUCLEAR FACILITIES

3.1 Nuclear Production Forecast

(Issue 5.5)

A key component of this Decision is the Board's determination of the appropriate nuclear production forecast for the determination of the payment amounts. OPG used the same methodology to determine the production forecast as in the previous proceeding. This resulted in a forecast of 48.5 TWh for 2014 and 46.1 TWh for 2015. OPG's historical nuclear production and test period production forecast are summarized in the following table.

Table 12: Nuclear Production Forecast

TWh	2010 Plan	2010 Actual	2011 Approved	2011 Actual	2012 Approved	2012 Actual	2013 Budget	2013 Actual	2014 Plan	2015 Plan
Darlington	27.8	26.5	28.9	29.0	29.0	28.3	26.9	25.1	28.4	26.1
Pickering	20.3	19.2	22.0	19.7	23.0	20.7	21.1	19.6	21.3	21.9
Total		**45.7**	**50.9**	**48.7**	**52.0**	**49.0**	**48.0**	**44.7**	**49.7**	**48.0**
Exhibit N1 Update - Darlington									28.1	24.7
Exhibit N1 Update - Pickering									20.9	21.3
Total - revised N1									**49.0**	**46.1**
Exhibit N2 - Darlington (no change from N1)									28.1	24.7
Exhibit N2 Update - Pickering									20.4	21.3
Total - revised N2									**48.5**	**46.1**
Sources: Exh E2-1-2, Exh L-1-Staff-2, Exh N1-1-1, Exh N2-1-1										

OPG's test period forecast includes a 0.5 TWh adjustment (a reduction) in each year for major unforeseen events. This level of adjustment was approved for the first time for the 2011-2012 test period in the Board's previous decision.

The Exhibit N1 update is based on selected updates from the 2014-2016 business plan. The number of planned outage days at Pickering increased by 86.6 days which reduced the test period production forecast by 1.0 TWh. Darlington's production forecast was reduced by 1.6 TWh due to an increase in planned outage days and a reduction of 0.28 TWh related to higher lake water temperature.

The Exhibit N2 update is based on a further increase of 21 planned outage days at Pickering and a higher forecast of forced loss rate at Pickering resulting in a production forecast decrease of 0.5 TWh in 2014.

No party proposed changes to the Pickering production forecast.

Board staff submitted that the 61.9 day increase in outage days at Darlington is responsive to OPG senior management business planning direction to consider the significant historical variances. The major 2015 Darlington outage is related to moving the planned vacuum building outage from 2021 to 2015. OPG states that the length of the 2015 vacuum building outage is dependent on emergency service water piping work and emergency coolant injection valve replacement. Board staff questioned why this critical path work was not identified in the initial application. Board staff submitted that a production forecast reduction of only 0.28 TWh related to higher lake water temperature was appropriate for the test period.

The Board staff submission was supported by most parties. However, AMPCO submitted that the Darlington production reduction related to higher lake water temperatures should not be approved. In AMPCO's view the 2014-2016 business plan is based on the actuals prior to 2013. The actual production losses due to high lake water temperature in 2013 are much lower than 2012, and AMPCO submitted that the Board should not approve the 0.28 TWh reduction.

The challenge of the nuclear production forecast by OPG senior management is part of the review that all production forecasts are subject to, and the process surrounding the update was not different. OPG submitted that the adjustment was the result of rigorous reassessment and lessons learned from recent outages. While the specific tasks on the critical path are not discussed in detail in the pre-filed evidence, the complexity of the vacuum building outage is discussed. OPG observed that the Board staff submission focused on the tasks during the vacuum building outage but ignored the updated evidence that 22 of the 61.9 outage day increase is related to other Darlington outages.

Production losses related to lake water temperature are based on reviewing historical performance. OPG submitted that the evidence is based on the best information available and that AMPCO's submission should be given no weight.

Board Findings

The Board approves a nuclear production forecast of 49.0 TWh for 2014 and 46.6 TWh for 2015 to be used in the calculation of payment amounts.

OPG's forecast as filed in the updated impact statements (Exhibits N1 and N2) is accepted with one exception as discussed later in this Decision. The forecast as amended by updates filed in December 2013 and May 2014 was based on the business plan for 2014 to 2016. This business plan addresses the historically large and persistent gap between forecast and actual nuclear production. The revised forecast is in response to Senior Management's direction and was to ensure that the planned outage days recognize the scope and complexity of the proposed work. The revised forecast in Exhibit N2 reflects a more complete understanding of the work required at the Pickering units. As a result, the Board agrees with OPG that the nuclear production forecast represents "OPG's most complete and accurate forecast for 2014 and 2015".[31]

The decrease in production forecast for 2015 is the result of the decision to combine work at Darlington to include a vacuum building outage, a station containment outage and critical path work related to emergency service water piping work and emergency coolant injection valve replacement. The Board finds that OPG has demonstrated that combining this work results in net positive benefits and has been already approved by the Canadian Nuclear Safety Commission. The Board accepts that this work should be undertaken in 2015 and will result in a reduced forecast of nuclear production [32]

The one exception to accepting the nuclear production forecast as proposed by OPG is that the Board will remove the adjustment for major unforeseen events of 0.5 TWh for each of 2014 and 2015. This adjustment is tied to the Board's acceptance of OPG's evidence that the forecasts are based on OPG's best evidence which explains the technical and operational reasons for its updates to the production forecast, and that the resulting forecast is as accurate as possible. It follows then, that with the confidence OPG has in its forecast and the more detailed scrutiny which was undertaken in producing this forecast, that an allowance for unforeseen events is no longer required.

The Board finds that the argument of some parties for further adjustments to the forecast, for example due to water temperatures, is not compelling.

[31] Argument-in-Chief page 63
[32] Argument in Chief page 63

The quantity of nuclear production of 49.0 TWh in 2014 is equal to the highest amount over the period 2008 to 2013 and is therefore considered by the Board to be achievable and reasonable. The forecast amount of 46.6 TWh for 2015 is also considered by the Board to be reasonable.

3.2 Nuclear OM&A and Benchmarking

(Issues 6.3 and 6.4)

OPG seeks approval of operating costs of $2,957.5M in 2014 and $2,985.2M in 2015 for the nuclear facilities. The nuclear facility operating costs include base, project and outage OM&A, Darlington Refurbishment and New Nuclear OM&A, an allocation of corporate support and centrally held OM&A, nuclear fuel costs, Pickering Continued Operations costs, and depreciation and taxes. This section of the Decision addresses nuclear OM&A costs and benchmarking. The other components of nuclear operating costs are discussed later in this Decision.

OPG's historical and forecast OM&A for the nuclear facilities are summarized below. OPG applied for a total OM&A budget $2,401.4M for 2014 and $2,419.8M for 2015. The compound annual growth rate from 2010 actual to 2015 forecast is 3.5%.

Table 13: Nuclear OM&A

$million	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Plan	2015 Plan
Base	1,181.4	1,249.1	1,102.6	1,127.7	1,151.1	1,154.0
Project	142.7	111.6	111.5	105.7	113.9	106.4
Outage	278.2	215.0	214.3	277.5	262.7	330.7
SubTotal Operations	1,602.3	1,575.7	1,428.4	1,510.9	1,527.7	1,591.1
Darlington Refurbishment	3.2	2.6	2.8	6.3	19.6	18.2
Darlington New Nuclear	23.2	15.7	24.7	25.6	-	-
Corporate Costs	226.5	233.1	408.4	428.3	433.9	417.4
Centrally Held Costs	161.6	267.1	342.7	409.9	418.2	419.8
Asset Service Fee	24.5	22.1	23.0	22.7	23.3	26.8
SubTotal Other	439.0	540.6	801.6	892.8	895.0	882.2
Total OM&A	**2,041.3**	**2,116.3**	**2,230.0**	**2,403.7**	**2,422.7**	**2,473.3**
Exhibit N1 Update					**2,491.8**	**2,531.3**
Exhibit N2 Update					**2,401.4**	**2,419.8**
Sources: Exh L-1-Staff-2 Table 19, Exh N2-1-1						

Some parties proposed reductions to the OM&A forecast. These reductions ranged from $100M in the test period (Board staff), $100M per year (SEC and LPMA), $150M per year (CME), to $1.225 billion (GEC). The supporting rationale for the reductions was poor benchmarking results or excessive compensation. Part of Board's staff's proposed reduction was also based on excessive corporate support cost. OPG replied that the proposed reductions are punitive and that none of the parties challenged specific evidence related to base, project and outage OM&A.

Environmental Defence submitted that $1 billion of the test period OM&A expense is related to Pickering. It argued that this amount is unreasonable as other power sources, for example, conservation and imports from Quebec, are more cost-effective. Environmental Defence submitted that the operation of Pickering will also curtail renewable power generation. OPG argued that it is improper to determine payment amounts on the basis of the cost of other sources of power. Further, there is an insufficient record to assess cost and practicality of other sources of power.

Benchmarking

Benchmarking of the nuclear facilities is mandated by the August 17, 2005 Memorandum of Agreement between OPG and the Shareholder.[33]

> OPG will seek continuous improvement in its nuclear generation business and internal services. OPG will benchmark its performance in these areas against CANDU nuclear plants worldwide as well as against the top quartile of private and publicly- owned nuclear electricity generators in North America. OPG's top operational priority will be to improve the operation of its existing nuclear fleet.

The Memorandum of Agreement further requires that:

> OPG will annually establish 3 –5 year performance targets based on operating and financial results as well as major project execution. Key measures are to be agreed upon with the Shareholder and the Minister of Finance. These performance targets will be benchmarked against the performance of the top quartile of electricity generating companies in North America.

[33] Appendix C of this Decision

In the first cost of service proceeding, the Board found that the benchmarking filed was insufficient. As a result, the Board directed OPG to retain an expert to prepare a comprehensive benchmarking analysis of OPG's nuclear operations. OPG filed benchmarking reports that assessed 2008 performance prepared by ScottMadden Inc. for the EB-2010-0008 proceeding. OPG has adopted the ScottMadden reporting format and annually benchmarks its nuclear performance against "20 performance metrics and then sets operational, financial and generation performance targets that will move OPG nuclear closer to top quartile industry performance over the business planning period as part of top-down business planning process adopted in response to ScottMadden's work."[34]

The results of OPG's benchmarking of three key metrics for the nuclear facilities for the period 2008 to 2013, and the targets for 2014 and 2015 are summarized in the following table.[35] The three key metrics identified by ScottMadden are World Association of Nuclear Operators Nuclear Performance Index, Unit Capability Factor and Total Generating Costs per MWh. Note that Pickering A and B were combined by OPG after 2010, and therefore the units are not ranked separately by OPG after that time (though ScottMadden had created separate targets for Pickering A and B in its 2009 report). OPG has performed very poorly on all three of the key metrics.

[34] Reply Argument page 139
[35] Undertaking J5.2

Table 14 – Summary of Nuclear Benchmarking

	---Rolling Actual Results---						---Annual Target ---		
	a	b	c	d	e	f	g	h	i
Darlington	2008	2009	2010	2011	2012	2013	**2014** "Scott Madden" Phase 2 Report	**2014** 2013-2015 Business Plan	**2015** 2013-2015 Business Plan
WANO NPI (Index)	95.67	95.10	94.10	92.80	96.30	90.75	98.60	97.90	96.10
2-Year Unit Capability Factor (%)	91.99	90.20	89.40	89.60	92.00	90.44	93.30	93.50	86.30
3-Year Total Generating Costs ($/New MWh)	30.08	32.77	33.55	33.05	31.67	34.42	36.75	36.21	42.78
Pickering									
WANO NPI (Index)	60.90	67.17	64.30	66.10	64.70	67.52	77.83	72.00	74.20
2-Year Unit Capability Factor (%)	67.65	74.47	74.57	72.50	75.62	75.77	82.10	79.90	82.10
3-Year Total Generating Costs ($/New MWh)	67.05	66.42	65.62	65.86	67.16	67.18	66.84	66.08	60.25
Pickering A									
WANO NPI (Index)	60.84	61.10	47.70				70.90		
2-Year Unit Capability Factor (%)	56.60	68.00	63.30				84.30		
3-Year Total Generating Costs ($/New MWh)	92.27	95.41	90.21				70.81		
Pickering B									
WANO NPI (Index)	60.93	70.20	72.60				81.30		
2-Year Unit Capability Factor (%)	73.17	77.70	80.20				81.00		
3-Year Total Generating Costs ($/New MWh)	58.68	54.64	54.79				64.80		

Q1
Q2
Q3
Q4

Sources:
Column a - EB-2010-0008 Exh F5-1-1 page 12 (Scott Madden Phase 1)
Column b - EB-2010-0008 Undertaking J3.5 Attachment 1 page 4
Column c - Exh L-6.4-SEC-92
Column d - Exh F2-1-1 Attachment 1 page 3
Column e - Exh L-6.4-SEC-92
Column f - Vol 5 Oral Hearing Transcript June 18, 2014
Column g - EB-2010-0008 Exh F2-1-1 Attachment 1 (Annual Targets agreed based on Scott Madden for inclusion in 2010-2014 Business Plan)
Column h- EB 2013-0321 Exh F2-1-1 page 15 (Annual Targets)
Column i - Exh F2-1-1 Attachment 2 (2013-2015 Nuclear Business Plan - Annual 2015 Target)

OPG Nuclear	2008	2011
WANO NPI (Index)	17th out of 20	24th out of 27
2-Year Unit Capability Factor (%)	18th out of 20	25th out of 28
3-Year Total Generating Costs ($/New MWh)	16th out of 16	12th out of 14

Table 14 was initially prepared by Board staff for cross examination and subsequently reviewed by OPG and filed as undertaking J5.2.

Column g of Table 14 lists the 2014 targets OPG established with ScottMadden in 2009. It was recognized at the time that the targets would not result in best quartile performance but that achievement of the targets would close the gap. Board staff submitted that OPG's performance to date and the test period targets fall short of these targets. During the oral hearing, OPG's witness indicated that achieving top quartile is not an objective.[36] Board staff submitted that the Memorandum of Agreement could have referred to benchmarking without referring to top quartile, and that it is clearly the shareholder's expectation that OPG set targets to achieve top quartile. CME submitted that OPG's performance as set out in Table 14 falls far short of what ratepayers should reasonably expect. CME noted that in the previous proceeding, the Board sent a signal that OPG must take responsibility for improving its performance by reducing the nuclear payment amounts by $145M.

Using data in the benchmarking report for 2011 filed with the application,[37] Board staff estimated that annual nuclear costs would be reduced by $300M if OPG's total generating costs were at the midpoint for the comparators. Board staff did not propose disallowances of this magnitude, but submitted that it would be reasonable for the Board to expect that OPG's efficiency and productivity should be improving. Recognizing that total generating cost includes OM&A, fuel and some capital costs, CME submitted that an OM&A reduction of $150M per year was appropriate.

The Pickering units, in particular units 1 and 4, perform poorly compared to the targets established. GEC submitted that, while OPG and the shareholder may want to run uneconomic plants, the issue before the Board is whether it is appropriate to allow full recovery of the costs OPG proposes. GEC estimated that test period OM&A requirements would be reduced by $1.225 billion based on industry median levels for Pickering, and reduced by $322M if Pickering operated at OM&A levels similar to Darlington. GEC submitted that OPG should be required to study the economics of a range of Pickering shutdown scenarios for the next proceeding.

OPG stated that there have been positive developments in benchmarking and cited Pickering unit-specific forced loss rate and unit-specific capability factor improvements. It is premature to state that OPG will not meet 2014 targets for the key metrics. OPG expects that Darlington 2014 total generating cost will be marginally below best quartile and that the total generating cost gap at Pickering has narrowed. OPG argued that the disallowances proposed by Board staff and CME should be rejected as the benchmarking report for 2011 does not reflect the impact of the Business Transformation initiative. OPG also referred to the Goodnight Consulting Inc. staffing study. OPG indicated that Goodnight determined that due to technology differences,

[36] Tr Vol 6 pages 119-120
[37] Exh F2-1-1 Attachment 1

OPG's CANDU plants require 1,431 more Full Time Equivalents ("FTEs") than comparator plants and eliminated these FTEs from the staffing study. OPG estimated that this represents $184M of unavoidable OM&A.

As the shareholder has concurred with the business plans that underpin the application, OPG replied that the shareholder has no concerns with OPG's performance under the Memorandum of Agreement.[38] OPG argued that it is not contractually committed to, or required to target or perform to top quartile standards, and that it is not aware of any case where the Board considered failure to achieve top quartile performance in setting rates.

Board Findings

The benchmarking of OPG's nuclear operations is an important reference for the Board. OPG has continued to produce annual nuclear benchmarking reports based on the format and methodology set out in 2009 by the consulting firm ScottMadden. The benchmarking is responsive to the Memorandum of Agreement with the Shareholder and provides the Board with comparative information for its review in a cost of service application. It is the Board's expectation that OPG will continue to produce annual nuclear benchmarking reports based on the ScottMadden methodology and that OPG will file these reports in future cost of service applications.

The benchmarking results for 2008 to 2013 and the targets for the test period were reviewed in this proceeding. The analysis was complicated by the presentation of rolling averages for the historical period and annual targets for the future period. The analysis was further complicated by the reorganization of Pickering. The Board recognizes that some individual units at Pickering and Darlington have improved performance in one or more of the metrics. In OPG's view, it has improved as a major operator in the three key metrics, but in comparison to the industry, OPG is just stable, because the industry also is changing.

Despite these factors, there is no dispute that OPG's performance in the three key metrics is not top quartile, nor does it demonstrate continuous improvement. In fact, for many of the measures OPG remains in the third or fourth quartile. It is also reasonable to conclude that OPG will not reach the aspirational 2014 targets set by ScottMadden and OPG in 2009 in order to close the gap. This is not the type of performance that

[38] Reply Argument page 134

ratepayers would expect. OPG is not satisfied with its performance either: "… clearly we would like to see better performance from our plants."[39]

In its submission, Board staff included calculations of the cost of OPG's performance relative to the midpoint for comparators' total generating cost for 2011 for illustrative purposes. CME submitted that a $150M OM&A reduction per year was appropriate on the basis of this gap. The Board agrees with OPG that reductions of $150M to $300M per year on the basis of nuclear benchmarking is not appropriate as the impact of Business Transformation is not reflected in the 2011 total generating costs. However, the Board notes that OPG's total generating cost targets for 2014 and 2015 take into account Business Transformation and those targets are second and third quartile.

OPG also argued that the Board staff and CME calculations were flawed as there is unavoidable OM&A related to the CANDU technology. The Board does not agree that the calculations were flawed for this reason. The ScottMadden methodology, which has been accepted by OPG for benchmarking, considered technology differences and found that the best overall financial comparison metric for OPG facilities is total generating cost per MWh.

Both Environmental Defence and GEC have proposed significant reductions related to poor economic performance of the Pickering units. The Board does not agree with these submissions. The government's direction on the operation of Pickering is set out in the Long-Term Energy Plan.

The Board finds that OPG's proposed nuclear OM&A costs should be reduced. The Memorandum of Agreement provides that "OPG's top operational priority will be to improve the operation of its existing nuclear fleet." In conjunction with ScottMadden, OPG itself set targets for 2014 that will not be met. Although the Memorandum of Agreement is not a contract for this purpose, it is clearly OPG's shareholder's intention that OPG improve continually, and at least target top quartile performance. OPG accepts that benchmarking is a valuable tool, and accepts that it has not achieved the results it wanted to achieve. It does not appear to accept, however, that there should be any repercussions from this poor performance in the way of disallowances. Benchmarking serves as a guide only. However, it is clear that OPG's inability to achieve even average performance imposes a significant cost on ratepayers. The Board finds that it is not reasonable to pass all of these costs on to ratepayers.

[39] Tr Vol 6 page 13

There is no specific budget "line item" related to overall nuclear performance and benchmarking. However, the majority of OM&A costs are predominantly related to staffing levels, compensation and pension related costs. Therefore, the Board's disallowances with respect to this issue are incorporated within its disallowances under the compensation section of this Decision.

3.3 Nuclear Fuel

(Issue 6.5)

Nuclear fuel costs include the cost of fuel bundles, used fuel storage cost and fuel oil for standby generators. As updated in Exhibit N2, OPG has forecast an amount of $266.5M for nuclear fuel procurement for 2014 and $260.5M for 2015.

AMPCO submitted that based on the average of 2010 to 2013 actuals, the test period fuel oil expense should be reduced by $3.5M. OPG did not respond to this submission.

In response to direction from the previous cost of service decision, OPG filed the Uranium Procurement Program Assessment Study prepared by Longenecker and Associates ("Longenecker").[40] Longenecker confirmed that US nuclear generators require inventory of 30 to 35% of annual requirements. OPG stated that test period carrying costs would be reduced by $4.7M if OPG's inventory levels were reduced to 30%. CME submitted that a reduction of $4.7M is appropriate. OPG argued that CME's proposal was unreasonable as contractual obligations as well as financial and physical risk coverage limits need to be considered.

CME observed that the proposed fuel costs are higher than historical and submitted that each test year be no more than the 2013 expense of $244.7M. OPG replied that there is no support for this submission as fuel expense is a function of production. In addition, OPG indicated that the 2013 fuel expense was based on production of 44.7 TWh and the production forecast for each test year is higher.

Board staff suggests that OPG be required as part of its next payments application to provide a study demonstrating how its nuclear fuel requirements and cost estimates reflect appropriate strategies for balancing costs and risks. Further, Board staff suggested that the analysis be based on the approaches that OPG has found

[40] Exh F5-2-1

appropriate and that Longenecker found to be “good utility practice” in its study. Board staff suggested OPG should also provide details regarding planning for lower nuclear fuel inventory requirements for when Pickering will cease operations. OPG argued that the Longenecker study was completed in 2012 and as Board staff had no issues with the findings, there was no need for a new study.

Board Findings

The Board finds that OPG met the directive in the EB-2010-0008 decision when it commissioned Longenecker, an independent consultant, to conduct a review of OPG’s uranium procurement program.

The Board accepts the findings in the Longenecker & Associates report which concludes that OPG’s procurement is undertaken in a professional manner and that its strategy is prudent. The Board is encouraged that three of the four recommendations made in the report have been accepted and are being implemented. The one recommendation not being pursued by OPG is with respect to “off-market” transactions. The Board agrees this recommendation is inconsistent with OPG’s policy and the government’s procurement guidelines to which it is subject.

The Board will not make any changes to OPG’s proposed inventory target levels, which will be achieved by the end of 2015. The observation that the reduced inventory levels may be achieved by the end of 2014 is unsupported.

The Board does not agree that a study to examine various nuclear fuel cost management options in anticipation of the changes once the Pickering station is closed should be undertaken at this time. Given the station is not proposed to close until 2020, the Board agrees with OPG that undertaking such a study would not be a reasonable expenditure of time and money.

Although several parties put forward suggestions for reducing the nuclear fuel cost expenditures, there was no substantial evidence provided regarding the options proposed. As OPG points out, fuel expenses are a function of production, so a simple comparison of costs in the previous three years is not a suitable predictor of future costs.

The Board finds OPG's proposed costs of $266.5M for 2014 and $260.5M for 2015 to be reasonable and are therefore accepted. However the final nuclear fuel cost will increase due to the increased nuclear production forecast the Board has set. OPG shall confirm the final test period nuclear fuel costs in the payment amounts order process.

3.4 Pickering Continued Operations

(Issue 6.6)

Pickering Continued Operations will extend the life of Pickering units 5 to 8 from 2015/2016 to 2020. OPG seeks approval of 2014 OM&A expense of $38.9M for the project which would bring the total project cost to $192M.

OPG filed an updated 2012 business case for the project.[41] OPG reported that the net system benefit of Pickering continued operations is $520M. An OPA letter filed with the application suggested that the cost advantage of Pickering continued operations is $100M. The OPA did not provide oral testimony in the proceeding, but did file written responses on July 25, 2014 to questions raised by GEC relating to Pickering continued operations.

Board staff submitted that the test period expenditures are appropriate and that for the test period, the Board should rely on the Long-Term Energy Plan which states;

> The continued operation of Pickering facilitates the refurbishment of the first units at Darlington and Bruce by providing replacement capacity and energy without greenhouse gas emissions while managing prices. However, an earlier shutdown of the Pickering units may be possible depending on projected demand, the progress of the fleet refurbishment program, and the timely completion of the Clarington Transformer Station.[42]

AMPCO submitted that the net present value of continued operations is high, as the analysis did not consider sunk costs of $140M, a low demand scenario and risk related to pressure tube and calandria contact. AMPCO did not support any continued operations expenditure as it believes that the net present value of continued operations is a cost not a benefit. OPG argued that the business case included contingency for the issue of the potential risk associated with the pressure tube and calandria contact.

[41] Exh F2-2-3 Attachment 1
[42] Exh KT2.2 page 30

GEC observed that there is a considerable difference between the continued operations benefit determined by OPG and the OPA. GEC questioned the factors analyzed in the sensitivity analysis. In particular, GEC questioned whether the full cost of surplus baseload generation was considered by OPG and the OPA. In GEC's view, the Board should not approve payment amounts that have a perverse effect on ratepayers. As the economic benefit of continued operations is questionable, GEC submitted that the incremental cost of running Pickering in the test period ($126M in 2014 and $310M in 2015) should be disallowed.

OPG argued that OPA analysis did consider potential surplus energy and that this was confirmed in the written responses filed by the OPA on July 25, 2014.

GEC recognizes that operation of some Pickering units has system planning benefits, however, as units 1 and 4 (formerly Pickering A) under-perform on all benchmarking indicators versus units 5 to 8 (formerly Pickering B), GEC submitted that the Board should not "reward" OPG for the continuing losses with respect to units 1 and 4. OPG replied that it operates Pickering as one station and that the Long-Term Energy Plan includes Pickering in-service beyond the test period.

GEC submitted that $6.6M of test period expense allocated to Pickering for the fuel channel life extension project should be allocated to Darlington as the additional fuel channel life is not required for Pickering station life of 2020. However, OPG argued that an objective of the fuel channel life extension project is to operate all Pickering units to 2020 without a life management outage on any unit.

In the event the Board is not prepared to implement cost reductions related to Pickering, GEC submitted that the Board should require OPG to provide, in the next payment application, a detailed analysis of the net benefits of continued operation of Pickering units. GEC further submitted that the analysis should consider shutdowns of either the A or B units or all units, including staffing considerations. OPG argued that the study should not be ordered and that the Board should rely on the Long-Term Energy Plan.

Board Findings

The Board approves the OM&A costs in the amount of $38.9 M to enable the completion of the initiative to extend the operating life of Pickering units 5 to 8 to the year 2020. The Board finds these costs to be prudent and notes that this initiative is on time and on budget to be completed by the end of 2014.

The 2014 costs to complete the continued operations initiative include Fuel Channel Life Extension costs. The Board does not accept GEC's argument that these should be disallowed or reallocated to Darlington. OPG's evidence demonstrates that these costs are related to Pickering continued operations.

It is important to recognize that the extension of the Pickering units is consistent with the Province of Ontario's Long-Term Energy Plan. Further, benefits from Pickering continued operations were confirmed by the OPA. Lastly, the continued operations of Pickering has been reviewed by the Canadian Nuclear Safety Commission resulting in the renewal of Pickering's power reactor operating license to August 31, 2018.

Challenges to the value and economic merits of the Pickering continued operations were made by GEC and AMPCO, including whether the analysis was incorrect as the assessment omitted the impact of surplus generation. The Board accepts OPG's evidence that surplus baseload generation was included in the OPA's analysis.

The Board reiterates its view that the project is consistent with government direction, and that benefits (while significantly reduced from OPG's estimate) were determined by the OPA to be positive. The OPA also brought to the Board's attention the non-economic benefits of Pickering Continued Operations. For these reasons, the Board does not see the value of directing OPG to complete a detailed analysis of the net benefits of continued operation of Pickering units.

3.5 Nuclear Capital Expenditure and Rate Base

(Issues 2.1, 4.6, 4.7 and 4.8)

OPG has applied for total capital expenditures of $196.3M in 2014 and $143.9M in 2015, excluding the Darlington Refurbishment Project. The proposed capital expenditure for 2014 represents a decrease over 2013 actuals. OPG states that the decrease in 2015 is due to a reduction in the number of capital projects. OPG also seeks Board approval for nuclear in-service additions of $158.3M for 2014 and $141.7M for 2015.

OPG's historical and forecast capital expenditures for the nuclear facilities, excluding Darlington Refurbishment, are summarized in the following table.

Table 15: Nuclear Operations Capital Expenditures (excluding Darlington Refurbishment Project)

$millions	2010 Budget	2010 Actual	2011 Approved	2011 Actual	2012 Approved	2012 Actual	2013 Budget	2013 Actual	2014 Plan	2015 Plan
Darlington NGS	24.3	33.8	12.8	47.9	5.6	50.5	68.8	76.4	20.6	9.5
Pickering NGS	22.6	93.0	1.5	56.1	0.5	78.7	67.2	90.6	22.2	2.2
Nuclear Support	58.0	30.1	3.9	31.2	0.7	16.7	13.0	24.0	4.2	1.3
Total Portfolio Projects (Allocated)	104.9	156.9	18.2	135.2	6.8	145.9	149.0	191.0	47.0	13.0
Facility Projects (to be Released)	36.6	-	74.0	-	55.0	-	-	-	0.0	0.0
Portfolio Projects (Unallocated)	30.4	-	79.8	-	110.3	-	1.4	-	128.0	109.2
Total Portfolio Projects	171.9	156.9	172.0	135.2	172.1	145.9	150.4	191.0	175.0	122.2
P2/3 Isolation	8.8	5.9	-	-	-	-	-	-	0.0	0.0
Minor Fixed Assets	20.2	15.4	19.7	12.9	19.5	15.5	19.9	10.2	21.3	21.7
Total Nuclear Operations Capital	**200.9**	**178.2**	**191.7**	**148.1**	**191.6**	**161.4**	**170.3**	**201.2**	**196.3**	**143.9**

Source: Exh D2-1-2 Table 4 & Exh L -1-Staff-2 Attachment 1 Table 11

Based on historical overestimating of capital budgets and approvals, Board staff proposed that a 10% reduction to the requested amounts would be a more reasonable level of forecast expenditure. Several parties agreed with the Board staff submission. CME observed that a historical comparison of Board approved amounts with actuals results in a difference of 20%.

OPG submitted that the analysis of historical trends is not a review of reasonableness of the test period nuclear capital project forecast.

With respect to nuclear rate base additions excluding Darlington Refurbishment, a summary of historical and forecast additions is provided below.

Table 16: Nuclear Operations In-Service Additions (excluding Darlington Refurbishment Project)

	2010		2011		2012		2013		2014	2015
$millions	Budget	Actual	Approved	Actual	Approved	Actual	Budget	Actual	Plan	Plan
Darlington NGS	43.1	31.2	32.9	32.3	90.1	52.9	89.9	183.7	43.9	7.7
Pickering NGS	103.1	166.8	4.5	27.4	17.9	41.0	53.6	97.1	48.8	12.5
Nuclear Support Divisions	25.1	35.6	67.9	30.6	12.5	22.5	17.4	30.7	6.4	0.7
Supplemental in-Service Fcst	-	-	50.5	-	47.6	-	-		37.9	99.1
Minor Fixed Assets	20.2	15.4	19.7	12.9	19.5	15.5	19.9		21.3	21.7
TOTAL	**191.5**	**249.0**	**175.5**	**103.2**	**187.6**	**131.9**	**180.8**	**311.5**	**158.3**	**141.7**

Source: Exh D2-1--3 Table 4 & Exh L-1-Staff-2 Attachment 1 table 2

In the previous payments case, the Board expressed concern with the forecasting of nuclear in-service additions. The EB-2010-0008 decision states, "In the next proceeding, the Board will re-examine the issue of rate base additions and the accuracy of OPG's forecasts in this area."[43]

Board staff submitted that OPG has a recent history of over estimating in-service additions by 12% in the period 2010 to 2012, and submitted that the rate base should be adjusted to reflect a reduction of $18M and $17M from the proposed in-service amounts for 2014 and 2015 respectively. AMPCO and CME supported Board staff's submission.

OPG argued that Board staff's analysis was incorrect as the 2013 variance was not factored into the analysis.

Board Findings

The Board finds that OPG's proposed capital expenditure budget for projects coming into service during the test period is reasonable. The projects are supported by business cases approved by the appropriate level of authority within OPG. The Board is providing no explicit approval in this Decision for the capital budget associated with multi-year nuclear projects (excluding the Darlington Refurbishment Project) which do not come into service during the test period. Although OPG has underspent during the three year period from 2010 – 2012 relative to its approved or budgeted capital expenditures, this is not true of 2013. The Board notes variation in the actual capital expenditures ranging from $148.1M in 2011 to $201.2 in 2013. The requested capital expenditures for 2014 and 2015 fall in the range of previous actual expenditures.

With respect to in-service additions, the Board has reviewed the data over a longer term period (2010-2013). The Board notes that the actual additions to rate base vary, with 2013 actual in-service additions significantly higher than previous years. OPG's proposed in-service additions for the test period fall well within the range of historical actuals. The Board approves the proposed test period in-service additions for nuclear projects (excluding the Darlington Refurbishment Project) of $158.3M in 2014 and $141.7M in 2015.

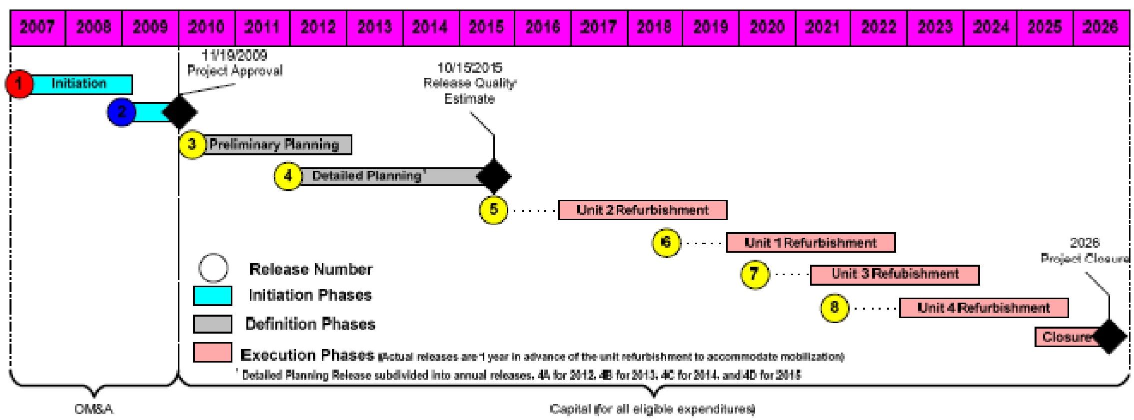
[43] Decision with Reasons, EB-2010-0008, page 59

3.6 Darlington Refurbishment Project

In February 2010, OPG announced it was proceeding with Darlington Refurbishment to extend plant life by 30 years to 2045-2050. OPG continues to have high confidence that the project will cost less than $10 billion (in terms of 2013 dollars) or $12.9 billion including capitalized interest and future escalation.

The refurbishment project phases are presented in the figure below.[44] This strategy was approved by OPG's Board of Directors in November 2013. The project is currently in the detailed planning and definition phase. A major milestone is the release quality estimate expected in October 2015, followed by refurbishment of Unit 2 in October 2016.

Figure 1: Overview of the Darlington Refurbishment Release Strategy



In the current proceeding OPG seeks:

- Approval of OM&A expenditures of $6.6M in 2014 and $18.2M in 2015.
- Approval of in-service additions to rate base of $5.0M in 2012, $104.2M in 2013, $18.7M in 2014 and $209.4M in 2015.
- A finding that proposed capital expenditures of $839.9M in 2014 and $842.5M in 2015 are reasonable.
- Recovery of capital cost portion of the Capacity Refurbishment Variance Account December 31, 2013 balance in the amount of $5.7M.
- A finding that commercial and contracting strategies are reasonable.

[44] Exh D2-2-1 Attachment 5 page 27

3.6.1 OM&A Expenditures (Issue 6.7)

Only Lake Ontario Waterkeeper ("Waterkeeper") made submissions on OM&A related to the Darlington Refurbishment Project. Waterkeeper submitted that the Board needs to ensure that adequate provision has been made for the environment, and that such a finding would fall under the Board's public interest mandate. Waterkeeper asked that the Board put two conditions on the approvals contained within this application.

First, that OPG be required to provide updates concerning the progress and actual costs of the Environmental Assessment Follow-up studies, other refurbishment project environmental monitoring studies and any adaptive management projects.

Second, Waterkeeper asked that the Board require OPG to provide detailed updates to show how its environmental oversight bodies have taken account of the environmental effects of the Darlington Refurbishment Project. Specifically, OPG should be able to demonstrate how they can prevent, mitigate and learn from environmental accidents or contingencies.

OPG argued that environmental regulatory oversight of OPG rests with the Canadian Nuclear Safety Commission, and that providing environmental assessment related filings to the Board is not required.

Board Findings

The Board approves OM&A expenditures of $6.6M in 2014 and $18.2M in 2015 for the Darlington Refurbishment Project.

The Board acknowledges that environmental regulatory oversight for the Darlington Refurbishment Project falls within the jurisdiction of the Canadian Nuclear Safety Commission. However, the Board is responsible for considering the costs that will ultimately flow through to payment amounts and will be borne by ratepayers. Accordingly, the Board will require OPG to file at its next cost of service proceeding updates of actual costs of environmental assessment follow-up studies, costs of environmental monitoring studies and costs of any adaptive management projects. The Board will impose the first condition on OPG as described by Waterkeeper. This condition relates directly to the Board's mandate to consider costs. The Board will not require OPG to provide the information contained in the second condition proposed by Waterkeeper. This information falls within the mandate of OPG's environmental regulatory authorities.

3.6.2 In-Service Additions to Rate Base (Issue 4.9)

As filed on September 27, 2013, OPG requested approval for Darlington Refurbishment Project in-service additions of $18.7M and $209.4M in 2014 and 2015 respectively.

OPG filed two updates to the Darlington Refurbishment Project evidence:

- As reported in Exhibit N1 filed on December 6, 2013, Darlington Refurbishment Project in-service additions were revised to $26.1M in 2014 and $310.0M in 2015.
- As noted in Exh D2-2-2 filed on July 2, 2014, in-service additions were revised to $67.2M in 2014 and $222.7M in 2015.

The original filing and the two updates for 2014 and 2015 in-service additions are summarized below.[45] The in-service additions are related to campus plan projects i.e. facilities and infrastructure, to support current operation, the refurbishment and operation after refurbishment. As the revenue requirement impact was not material, OPG did not propose any changes to its request for in-service amounts.

$ millions	Originally Filed Exhibit D2-2-1			As updated Exhibit N1-1-1 and D2-2-1 Attachment 5			As Updated Exhibit D2-2-2		
	Final In-Service Date	2014	2015	Final In-Service Date	2014	2015	Final In-Service Date	2014	2015
Darlington OSB Refurbishment	Jul-15	-	29.7	Oct-15	-	37.7	Aug-15	-	45.1
D2O Storage Facility	Apr-15	-	83.5	Oct-15	-	94.2	Jan-17	15.5	1.0
DN Auxiliary Heating System	Mar-15	-	36.3	Apr-15	-	43.5	Mar-15	-	75.3
Water & Sewer	Nov-14	12.2	-	Nov-13	-	-	Nov-15	22.6	6.6
Elec Power Distribution System	Apr-15	4.4	6.2	Jun-14	10.0	-	Nov-14	12.0	-
Darlington Energy Complex	Jul-13	-	-	Jul-14	6.0	-	Jul-15	2.1	4.1
RFR Island Support Annex	Apr-16	-	-	May-15	-	25.4	Apr-16	-	-
Other Campus Plan projects	various	-	-	various	10.2	-	various	15.1	7.6
Safety Improvement Opportunities	various	-	42.7	various	-	90.5	various	-	83.0
Other Station Modifications	various	2.1	11.1	various	-	18.7	various	-	-
Total		**18.7**	**209.4**		**26.1**	**309.9**		**67.2**	**222.7**

[45] Exh D2-2-2 page 6 Table 1

Environmental Defence submitted that the in-service additions are not appropriate as OPG has not established that the assets are required “but for” the Darlington Refurbishment. The assets will only provide benefit to ratepayers as part of the overall Darlington Refurbishment Project and should not be included in rate base until the refurbished units are in-service. One of the reasons that the Board rejected construction work-in-progress for the Darlington Refurbishment Project in the EB-2010-0008 proceeding was that it was still in the definition phase. Environmental Defence observed that the project is still in the definition phase.

Several parties sought clarification from OPG at the technical conference and oral hearing about its request with respect to Darlington Refurbishment in-service additions. Parties sought to understand the extent of project completion in the test period. In particular, the evidence filed in July 2014 indicated that the D2O (heavy water) storage facility and Auxiliary Heating System project were delayed and/or projected to be over-budget.

OPG indicated that costs and timelines for the D2O storage facility have changed as the scope of work was not well understood initially and there were new seismic requirements from the Canadian Nuclear Safety Commission. Similarly, OPG indicated there were scope changes arising from the contractor’s original underestimation of scope complexity for the Auxiliary Heating System project.

Based on its review of the evidence, which included reports of consultants retained by OPG to provide external independent oversight of the Darlington Refurbishment, GEC submitted that OPG has not demonstrated prudence in expenditure decisions, project planning or expenditure management. Even though some of the projects may be in-service, similar to Environmental Defence, GEC submitted that the projects are not required but for Darlington Refurbishment. Both Environmental Defence and GEC referred to an Alberta Court of Appeal decision that found that the used and useful principle requires that the facilities be required, not merely in use. However, in reply, OPG argued that the Alberta Court of Appeal decision was related to a provision of an Alberta statute that is not established law in Ontario.

Board staff and several other parties expressed some concern with OPG’s proposal to retain its original in-service addition request despite updated information about the status of individual campus plan projects. The parties proposed revisions to OPG’s request.

PWU submitted that OPG's proposal could be problematic for the Board to apply the principle of used and useful and to make a determination of what amounts should be added to rate base. The PWU's preference is for the Board to make a determination based on the updated in-service addition amounts.

In SEC's view, the rate base additions should be limited to $34.6M in 2014 and $6.6M in 2015 related to the water and sewer project and the electrical distribution project. There is insufficient evidence for some of the other projects and the remaining proposed additions should not be approved until the refurbished units are running. For projects for which there is insufficient evidence, SEC proposed additions to the Capacity Refurbishment Variance Account and review in a future application when supporting evidence was available. This matter is also noted in the Deferral and Variance Account section of this Decision.

Board staff recommended that the Board accept the amounts that OPG seeks to close to rate base, but that the approval should not be considered a finding of prudence for the D2O storage facility. CME agreed with staff, but submitted that a 10-20% reduction was appropriate to redress management failures identified by OPG's external consultant. VECC submitted that until the cost of managerial errors and remedial expenditures was independently determined, no additions to rate base should be approved.

It is OPG's view that all the campus plan projects will be used or useful when placed in-service and useful to the station generally, not wholly related to Darlington Refurbishment. There is sufficient evidence for all the projects and explanation for scope changes that led to cost increases for projects.

Board Findings

The Board will approve OPG's proposed test period in-service additions of $18.7M in 2014 and $209.4M in 2015.

Proposed in-service amounts represent assets that will come into service in the test period. OPG has sought to include some test period amounts which represent part of the larger Darlington Refurbishment Project. OPG submitted that the campus plan projects related to the proposed in-service additions are not wholly related to the Darlington Refurbishment Project, but are useful to the on-going operations of

Darlington as well. The Board has considered this evidence and agrees that the campus plan projects described are useful to the on-going operations of Darlington. The Board finds OPG's proposal to be reasonable in the specific circumstances in this case.

While Board staff agreed with the proposed amounts to be added to rate base for 2014 and 2015, they cautioned that the D2O project will not be fully complete until January 2017. Board staff agreed that a portion of the costs should be included in rate base but took the position that the Board's approval should not be considered to be a finding of prudence for the entire D2O project. The Board agrees. OPG has confirmed its understanding that the inclusion of test period amounts related to a portion of a project does not mean that the entire project is being accepted by the Board. A prudence review should take place when the D2O project is completed and fully in-service which it is expected will be OPG's next payment case.

The Board also considered the argument put forward by CME that a reduction of between 10-20% be made to the in-service additions related to the D2O project and the Auxiliary Heating System project. The Board accepts OPG's evidence that the increased costs represent more accurate project costs and therefore the Board will not require a reduction.

3.6.3 Test Period Capital Additions (Issue 4.10)

As originally filed in September 2013, Darlington Refurbishment Project capital expenditure was forecast to be $837.4M in 2014 and $631.8M in 2015. While the project is in the detailed planning and definition phase, facility and infrastructure projects to support or extend Darlington station life have commenced.

OPG updated its forecast of capital expenditure twice during the proceeding resulting in an increase of the proposed capital expenditures to $839.9M in 2014 and $842.5M in 2015.

Both Environmental Defence and GEC argued that the levelized unit energy cost analysis for Darlington Refurbishment is flawed and submitted that the capital expenditure request is not reasonable. Criticisms included consideration of externalities and limited costing of alternatives.

Board staff recommended that the Board not make a finding on the reasonableness of proposed capital expenditures as most of the projects would not go into service in the test period. Board staff indicated that the evidence was not complete regarding the amount comprising the updated capital expenditures for 2014 and 2015. OPG did not clarify or produce a list of projects in its reply argument. CME agreed with Board staff, noting that there was significant uncertainty around the estimates for projects making up the Darlington Refurbishment Project.

SEC also agreed with Board staff, noting that although there was a lot of evidence filed, it was not sufficient to allow the Board to make a binding determination on test period capital for Darlington Refurbishment. SEC noted that the independent reports on the campus plan projects were critical of the cost overruns, and submitted that the $1.7 billion proposal was unlikely to be correct and unlikely to be prudently incurred. OPG argued that the overall impact of the campus plan project overruns was minimal and that OPG has been responsive to the independent oversight of the project.

Board Findings

The Board indicated in an earlier ruling in this proceeding that it will not consider, as a threshold issue, whether the Darlington Refurbishment Project should proceed.[46] The Board maintains that the decision to refurbish Darlington is a decision that has been made by the provincial government and forms a key component of the Long-Term Energy Plan. As such, at this time the Board needs only to focus on the test period capital expenditures.

The Board notes that the majority of the capital expenditures proposed will not be added to rate base within the test period. The Board will not determine whether the amounts are reasonable or not, deferring that decision until OPG seeks to add these capital expenditures to rate base.

[46] Decision and Order on Issues List and Procedural Order No. 3, February 19, 2014, page 10, "…the examination of cost effectiveness of capital expenditure in the test period is within scope in this proceeding. Parties are reminded that the Board's jurisdiction is the setting of payment amounts and not the management of OPG's activities or the selection of generation options."

3.6.4 Commercial and Contracting Strategies (Issue 4.11)

OPG sought the Board's approval of its commercial and contracting strategies for the Darlington Refurbishment Project. OPG is utilizing a "multi-prime contractor model" where there is more than one prime contractor and the owner has a separate contract with each prime contractor. As the integrator between contractors, OPG retains project management responsibility and design authority. OPG has engaged external technical and project management experts to assist with this project management. The benefits of this model are that OPG retains control over the project, including deliverables, costs and schedules. OPG filed an Assessment of its Commercial Strategies prepared by Concentric Energy Advisors, dated September 2013.[47]

Many of the contracts will be target priced contracts. Under this model contractors receive incentives to meet cost and timeline targets. If the targets are missed, contractors will receive less incentive, but will receive payment for reasonably incurred expenses.

The strategies for the five major work packages (Re-tube and Feeder Replacement, Turbines and Generators, Fuel Handling, Steam Generators, and Balance of Plant) were reviewed by Concentric Energy Advisors. The Concentric reports filed with the application concluded that the strategies were reasonable and prudent.

In support of its application, OPG presented Mr. John Reed, a principal from Concentric Energy Advisors as a witness in the oral hearing. Mr. Reed stated in his evidence that for each of the major work packages for which Concentric offered an opinion, Concentric concluded that the company's conduct was within a range of "reasonable behaviour" and did represent "acceptable risk."[48]

It was not clear to Board staff or the parties what OPG was seeking from the Board related to commercial and contracting strategies or why such a finding was necessary. Board staff submitted that any decision on this matter would be a form of project management and that no specific approval should be provided.

[47] Exh D2-2-1 Attachment 7
[48] Tr Vol 13 pages 148-149

In SEC and CME's view, OPG's request is an attempt to "buy insurance" and to insulate OPG from commercial and contractual risks and from criticism in future proceedings. Approval of contracting and commercial strategies is neither necessary nor desirable.

OPG argued that a finding of reasonableness by the Board does not eliminate the need for future prudence review, but will enable the review to be assessed in the appropriate context.

Both GEC and Environmental Defence submitted that OPG's commercial and contracting strategies are contrary to the Long-Term Energy Plan as they expose ratepayers to too much risk. The evidence suggests that OPG bears the primary risk for overruns with respect to 93% of the project costs.[49] Environmental Defence was critical of cost overruns on previous projects including most recently the Niagara Tunnel Project and the Darlington Refurbishment campus plan projects. Environmental Defence submitted that there is no ratepayer protection for replacement power associated with project delays.

OPG clarified that the 93% of project costs includes OPG internal costs, and that only 27% of the $10 billion estimate is on a target price basis.[50]

GEC submitted that the project risk will not be monetized until the release quality estimate is complete; therefore, it is premature to structure the commercial arrangements and contract strategy. While OPG has stated that allocating more risk to contractors would have significant cost, GEC submitted that the commercial and contracting strategy should be informed by an understanding of the risks. Optimal allocation of those risks will enable compliance with the principles of the Long-Term Energy Plan.

OPG argued that GEC and Environmental Defence have taken a narrow view of risk. There is a multi-faceted risk minimization approach including OPG's retention of project management responsibility, a significant testing effort in advance of the release quality estimate and continuous internal and external oversight. While the parties claim that a fixed price turnkey arrangement is the only means to minimize risk, this is not possible for a mega project like Darlington Refurbishment as there are risks that contractors would not be willing to take on.

[49] Tr Vol 15 page 56
[50] Reply Argument page 107

Board Findings

The Board will not make a finding that the commercial and contracting strategies used by OPG in the Darlington Refurbishment Project are reasonable.

OPG proposed this issue in the draft issues list filed with the application. However, during the oral phase of the hearing it was unclear how a finding of reasonableness would be defined and why such an approval by the Board was necessary. On the last day of the hearing, in response to the Board's questioning as to what the Board would be approving if it determined that the contracting strategy was reasonable, OPG clarified that the Board would not be approving the contracts, it would not be approving the conduct of the contract negotiations, and it would not be approving the procurement process. The Board would not be approving any prices established through the contracting process, nor would the Board be approving the selection of the winning proponent(s).[51]

In OPG's view, the Board would be making a finding of reasonableness in respect of the guiding principles forming the contracting strategy which OPG described as including;

1. A multi-prime contractor model in which OPG retains overall project management and design authority responsibility;
2. The division of the work into 5 work packages;
3. A model where the prime contractor is responsible for some combination of engineering, procurement and construction within each of the 5 work packages; and
4. The means by which risk would be allocated.[52]

The Board will not make the finding requested by OPG for two reasons.

First, the application before the Board is an application for payment amounts for the years 2014 and 2015. The Board is of the view that the commercial and contracting strategies approval sought by OPG extends beyond a determination of those payment amounts. While there may be a tangential link between a contracting strategy and the rates requested, the Board finds that the link in this case is not direct enough. The Board agrees with Board staff that the request, as defined by OPG, is tantamount to an

[51] Tr Vol 16 page 5
[52] Tr Vol 16 page 4 (all subject to available contract options in the market place)

approval of project management which is not the role of the Board. Project Management and project execution are the responsibility of OPG.

If the Board were to make a finding on the reasonableness of the commercial and contracting strategies, the onus would be on OPG as the applicant to provide the Board with sufficient evidence to satisfy the Board that the commercial and contracting strategies are reasonable. Given the guiding principles articulated by OPG, the Board would have required far more evidence than was presented to reach those conclusions. On July 2, 2014, OPG filed reports that independently assessed the execution of some infrastructure projects related to the refurbishment. The reports prepared by Burns & McDonnell and Modus Strategic Solutions were critical of project execution and raised concerns including the impact on Darlington Refurbishment schedule and costs. In fact, the Board had to take a two-week recess from the proceeding to provide parties with the opportunity to review and analyze the reports filed on July 2, 2014.

The Board, in order to make any determination, must be satisfied that a thorough and complete hearing of this issue has taken place. The Board is not satisfied that this has occurred.

3.6.5 Darlington Refurbishment and Long-Term Energy Plan (Issue 4.12)

In Board staff's view, the Darlington Refurbishment is aligned with the Long-Term Energy Plan, however, the other parties submitted that it was premature to make a finding. OPG observed that the province has very clearly indicated that Darlington Refurbishment is a key part of the Long-Term Energy Plan and that no concerns have been raised with respect to compliance.

The Board will not opine on whether OPG's nuclear refurbishment process for Darlington aligns with the Government of Ontario's Long-Term Energy Plan. The Board considers this review to be outside of its mandate. A key component of the principles outlined in the Long-Term Energy Plan is the appropriate allocation of risk as it relates to nuclear refurbishment. The Board is of the view that for the reasons previously stated, the amount of evidence related to appropriate risk allocation would be insufficient for the Board to reach such a finding.

3.7 Nuclear Other Revenue

(Issue 7.2)

OPG receives revenue from non-energy businesses and that revenue is applied as an offset to the nuclear revenue requirement. These businesses are heavy water services, isotope sales and inspection and maintenance services. The nuclear facilities also provide ancillary services as described in the Hydroelectric Other Revenue section of this Decision. Variances between forecast and actual ancillary services revenue are recorded in the Ancillary Service Net Revenue Variance Account – Nuclear.

The table below sets out the actual and forecast levels for other revenue.

Table 17: Nuclear Other Revenue

$million	2010 Actual	2011 Actual	2012 Actual	2013 Budget	2013 Actual	2014 Plan	2015 Plan
Heavy Water Sales and Processing	26.7	80.9	55.1	18.9	34.8	26.3	20.4
Isotope Sales	10.1	4.8	11.5	11.1	7.0	11.6	11.9
Inspection & Maintenance Services	36.0	7.1	4.1	0.0	0.0	0.0	0.0
Helium 3 Sales	0.0	0.0	0.0	0.0	0.0	0.0	4.0
Costs	-31.5	-10.7	-8.7	-7.2	-5.9	-6.8	-7.8
Sub-total	41.3	82.1	62.0	22.8	35.9	31.1	28.5
Ancillary Services	2.6	2.4	1.8	1.9	1.7	1.9	1.9
Third Party Training	0.8	0.6	0.1	0.1	0.0	0.1	0.1
Total	**44.7**	**85.1**	**63.9**	**24.8**	**37.6**	**33.1**	**30.5**
Source: Exh G2-1-1 Table 1, Exh L-1-Staff-2 Table 35							

Board staff observed that OPG regarded its 2013 budget as "a return to more normal conditions for sales of heavy water, heavy water detritiation services and isotope sales."[53] However, the 2013 actual total other revenue was $12.8M or 51% higher than 2013 budget. OPG subsequently described the lower test period forecast as "a return to a more normal level of revenues for heavy water sales and processing."[54] Board staff submitted that the Board should consider the 2013 actual nuclear other revenue as the normal level for the test period and approve $37.6M for each of 2014 and 2015. OPG argued that heavy water sales and processing are subject to services provided to

[53] Exh G2-1-2
[54] Argument-in-Chief page 122

external parties and maintenance of the tritium removal facility and that it is not appropriate to consider just historical levels.

AMPCO submitted that OPG's 2014 and 2015 forecasts for Heavy Water Sales and processing are too low based on historical actuals, and proposed that a 4 year average be used to forecast the test period. LPMA proposed that a 3 year average be used. OPG argued that there is no pent up demand for heavy water sales and processing. The 2011 and 2012 revenues were related to the restart of Bruce and Point Lepreau reactors. OPG submitted that forecasting is more complex than relying on the past.

Board Findings

The Board accepts OPG's arguments that higher historic revenues in 2011 and 2012 from Nuclear Other Revenues may have been impacted by one-time events such as the increased sales to Bruce Power and Point Lepreau and may not be indicative of future revenues in the test period. The Board finds however that OPG has not substantiated its forecast decline for Nuclear Other Revenues. As a result, the Board finds the 2013 actual Nuclear Other Revenues of $37.6M to be appropriate for 2014 and for 2015.

4 CORPORATE COSTS

4.1 Compensation

(**Issue 6.8)**

Compensation is one of OPG's largest expenses. Compensation costs include salaries, wages, current pension expenses and other post-employment benefit ("OPEB") expenses and are expected to be $1,604.2M in 2014 and $1,618.1M in 2015; for a total of $3,222.3M in the test period. This amount is approximately 35% of OPG's annualized requested revenue requirement of $9.28 billion. There is no single "line item" for OPG's compensation costs. These costs are spread throughout various OM&A budgets and to some minor extent, are included in capital budgets.

The majority of OPG's compensation costs relate to its unionized work force in the PWU and the Society. Approximately 86% of compensation costs in 2014 are for employees represented by these two unions. OPG is required to collectively bargain with the PWU and the Society. The current collective agreement for the PWU covers the period April 1, 2012 to March 31, 2015. The Society collective agreement covers the period January 1, 2013 to December 31, 2015. OPG's position is that the requirement to bargain collectively with its unions places restrictions on its ability to control its compensation costs. The 2013-2015 business plan assumes no PWU increase for the period beginning April 1, 2015 other than a one per cent increase for step progression. For the Society the 2013-2015 business plan assumes a zero per cent increase over the test period, again with a one per cent increase for step progression.[55]

Broadly speaking, OPG's total compensation costs are the function of two things: the number of employees, and the amount that employees are paid, including pension expenses and benefits. Efforts to control costs can focus on either of these elements, or both.

Many parties argued that OPG's compensation costs are excessive, and that the Board should disallow recovery for a portion of the costs. CME argued that the evidence was clear that OPG is both overstaffed, and that its compensation levels significantly exceed industry benchmarks. It proposed disallowances of $146M in 2014 and $144M in 2015. SEC argued that although OPG had made significant progress in addressing its

[55] Argument-in-Chief page 4

overstaffing issues, its compensation levels remained excessive and that there were serious concerns regarding a lack of management oversight and accountability. SEC recommended disallowances of $100M in each of the test years. Both LPMA and CCC argued for the same reductions, on largely the same basis. Staff argued for OM&A reductions totaling $170M over 2 years, of which the majority would be attributable to compensation.

OPG submits that its compensation costs should be accepted by the Board as filed. It argued that there is no evidence that OPG could have reached a more favourable result through its collective bargaining and arbitration processes. OPG submits that it achieved very positive results in its most recent collective agreements: a "net zero" result for the PWU, and a modest wage increase for the Society, which was imposed by an arbitrator. OPG argues that it is legally required to collectively bargain within the confines of the Ontario *Labour Relations Act*, and that it achieved the best results possible under that framework. It relies on the evidence[56] of Dr. Richard Chaykowski, who testified that general compensation benchmarking studies are of limited value in a collective bargaining environment. The PWU and Society made similar arguments.

Board Findings

The Board has determined that it will disallow $100M from OPG's proposed total OM&A expenses in each of 2014 and 2015. This OM&A reduction relates directly to what the Board finds to be excessive compensation, and it applies to both the nuclear and hydroelectric businesses.

OPG's high total compensation costs have been a matter of concern for the Board for many years. In OPG's first payments proceeding (EB-2007-0905) the Board disallowed $35M in OM&A costs related to poor performance at Pickering A. The Board also found that OPG had not been responsive to benchmarking recommendations. The Board ordered OPG to conduct additional benchmarking studies for its next application.

The Board revisited compensation issues in OPG's second payments proceeding (EB-2010-0008). In that decision, the Board stated that it was "of the view that OPG has opportunities to reduce the overall number of employees further as a means of controlling total costs and enhancing productivity."[57] The Board also found that, "the

[56] Exh F4-3-1 Attachment 1
[57] Decision with Reasons, EB-2010-0008, page 85

[compensation] analysis provides sufficient evidence to conclude that for a significant proportion of OPG's staff the compensation is excessive based on market comparisons." The Board disallowed $145M in nuclear compensation costs over the two year test period. The Board further directed OPG to retain an expert to conduct benchmarking studies on its nuclear staffing and on its overall compensation levels.

Since the last payments case, OPG undertook a number of measures in an attempt to control its overall compensation costs. In 2011, OPG introduced a Business Transformation initiative to reduce staff levels in response to expected decreases in capacity and energy production in the coming years. The Business Transformation initiative has resulted in a steady decline in the number of employees in both the regulated and unregulated sides of its business. From 2011 to 2015, OPG will reduce its staff numbers by approximately 1,300 in its regulated businesses, which is more than 10% of its complement. OPG estimates that these staff reductions result in savings of approximately $550M – i.e. absent the Business Transformation initiative OPG would have incurred $550M more in costs for the period 2011 to 2015.[58]

Despite OPG's reduction of 10% of its workforce in the regulated business, total compensation amounts are forecast to go up over the test period: from $1,581M in 2010 to a forecast of $1,618.1M in 2015. This is due to higher average compensation per employee. The large average increases are driven in part by increased pension costs resulting from changes to the discount rate.[59]

The Board is not the only body that has expressed concern regarding OPG's compensation levels. On December 10, 2013, the Auditor General of Ontario released its annual report which included a review of OPG human resources polices over a 10 year period. The Auditor General noted that "OPG's generous compensation and benefits negatively impact electricity costs."[60] The Auditor General stated that despite the Business Transformation process, there are still many areas relating to compensation and benefits practices that need further improvement.[61]

[58] Exh A4-1-1
[59] Tr Vol 8 page 40 - MS. LADAK: Yes, in terms of total compensation, wages are going down as a result of headcount reductions. But as a result of pension increases, due to, largely, discount rate changes, total compensation is going up.
[60] News Release, Office of the Auditor General of Ontario, December 10, 2013
[61] Exh KT2.4, Annual Report of the Auditor General, page 153

There is significant evidence on the record that OPG's overall compensation costs are higher than they should be. This evidence includes the Auditor General's annual report (the details of which were reviewed with OPG in the hearing), the Goodnight Consulting report and the AON Hewitt report. The nuclear benchmarking reports based on the ScottMadden methodology further details OPG's poor overall cost effectiveness. These reports are discussed below. The Board observes a number of factors that drive these excessive compensation costs: too many staff and management, too much compensation (including pensions) for many of OPG's unionized employees, and a lack of management oversight with respect to performance management and overtime.

4.1.1 Staffing Levels

The following table summarizes historic and test period staffing levels.

Table 18: Staffing Levels

Full Time Equivalent ("FTE")	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Plan	2015 Plan
Nuclear	8,445.4	8,215.1	6,761.8	6,554.2	6,579.7	6,519.9
Previously Regulated Hydroelectric	359.7	369.4	343.8	321.5	343.1	340.9
Newly Regulated Hydroelectric	584.3	617.4	600.9	584.0	599.5	582.2
Allocated Corporate Support	1,091.4	1,072.4	2,299.0	2,142.7	2,043.8	1,952.6
TOTAL	**10,480.8**	**10,274.3**	**10,005.5**	**9,602.4**	**9,566.1**	**9,395.6**
Management	1,101.7	1,099.2	1,095.6	1,091.0	1,101.0	1,076.3
Society	3,269.0	3,254.6	3,112.6	2,909.2	3,043.3	2,965.6
PWU	6,012.9	5,840.7	5,711.0	5,542.0	5,371.7	5,300.3
EPSCA	97.2	79.8	86.3	60.2	50.1	53.4
TOTAL	**10,480.8**	**10,274.3**	**10,005.5**	**9,602.4**	**9,566.1**	**9,395.6**

Source: J9.7, EPSCA - Electrical Power Systems Construction Association

The area where OPG has made the most progress is with respect to staffing levels, as demonstrated by the staff reductions they have achieved through the Business Transformation initiative. At the Board's direction, OPG retained Goodnight Consulting Inc. ("Goodnight") to conduct a staffing benchmarking study for the nuclear business specifically.[62] Goodnight compared OPG's nuclear staffing levels against the 16 largest

[62] Exh F5-1-1

nuclear stations in the United States. Goodnight made certain adjustments to exclude activities specific to CANDU technology (which is not used in the United States), and to account for OPG's shorter work week. Goodnight was able to find suitable comparators for 5,574 positions. Goodnight was not able to benchmark 2,101 positions, mostly CANDU specific, due to lack of comparable benchmarks. Of the support functions, only corporate support dedicated to the nuclear business was considered.[63]

Goodnight concluded that, for the positions surveyed, OPG was 17% (866 positions) above the comparable benchmark as of July 2011. By February 2013 the situation had measurably improved: 7.6% (394 positions) over the benchmark. An update as of March 2014 showed additional improvement: 4.7% (244 positions) over the benchmark. By the end of the test period, OPG will likely be close to the benchmark level for the positions surveyed.

Although the Board recognizes that OPG has made progress in reducing its staffing numbers to approach industry standard levels, the Board finds that OPG remains overstaffed in the test period.

Several parties critiqued the Goodnight study, arguing that it was faulty because it did not include a large number of staff positions (and thereby likely underestimated the amount of overstaffing). They also argued that it failed to sufficiently recognize the unique features of OPG's CANDU technology (and thereby did not present a proper comparison for benchmarking). The Board is aware of the limitations of benchmarking, and recognizes that the Goodnight study cannot be expected to provide a precise "number" by which OPG is over (or under) staffed. The Board is satisfied, however, that Goodnight's methodology was sound and that its analysis is directionally correct. The Board finds that OPG is still moderately overstaffed with respect to the positions surveyed by Goodnight in the test period.

Several parties further noted that, although total employee numbers are down significantly, the number of management staff has barely moved: 1,101.7 in 2010 versus 1,101 and 1,076.3 forecast for 2014 and 2015 respectively. As a result, the percentage of employees that are managers has increased from approximately 10.5% in 2010 to 11.5% in 2015. The number of senior management and executive positions, the highest paid managers, has in fact increased significantly in recent years. The Report of the Auditor General revealed that from 2005-2012, the number of executives

[63] Exh F5-1-1 page 16

increased 74% and that the number of senior managers increased by 47%.[64] Many vice presidents and directors (40 as of 2012) do not have specific job titles or job descriptions. OPG stated that the duties and responsibilities of these vice presidents and directors would be set by their direct supervisors, but that there was no document describing what their job was.[65] OPG further stated that some of the increases in the number of senior management related to Business Transformation (5 directors) and the Darlington Refurbishment Project (13 directors).[66]

The Board finds that OPG has not sufficiently justified the number of its management positions. Business Transformation will result in the reduction of 1,300 positions for OPG's regulated business by the end of 2015, but the number of management positions is essentially unchanged. Although the Board accepts that there is not a perfect straight line correlation between decreases in non-management headcount and management headcount, the Board would expect a level of corresponding reduction for management positions. OPG submitted that increases in managers were necessary for Business Transformation and the Darlington Refurbishment Project. The Board finds that required increases in management associated with these incremental activities, are not sufficient to justify the total complement of management positions.

The costs related to excessive numbers of managers are significant. Had management positions been reduced in proportion to the reduction in overall staffing numbers, test period compensation would be lower. OPG's witness also confirmed that the Auditor General's report indicated there was an increase in senior management positions without formal job descriptions.[67] The Board finds this unacceptable. Management positions generally have the highest salary, pension and benefit costs. Basic controls must be utilized to justify each position on a needs basis and approvals must be documented. There is a cost associated with each position, and the needs and benefits must be clearly understood to justify the cost.

4.1.2 Compensation Per Employee

OPG's compensation package includes base salary, incentives, pensions and benefits. OPG's forecast average compensation per employee for 2015 is $205,914 for

[64] Exh KT2.4, Annual Report of the Auditor General, page 159
[65] Tr Vol 8 pages 106-107
[66] Undertakings J9.1 and J9.2
[67] Exh KT2.4, Annual Report of the Auditor General, page 159

Management, $176,508 for Society employees, and $163,458 for PWU employees.[68] This represents a significant increase in average compensation since 2010: 1.82% for Management, 10.35% for Society employees, and 19.73% for PWU employees. OPG stated that it is required to collectively bargain with its unionized employees, which places restrictions on its ability to reduce compensation levels and, to a lesser extent, staffing levels. OPG has more flexibility with respect to management compensation.[69]

The Auditor General's report raised many concerns regarding OPG's compensation levels and practices, many of which were reviewed through the course of the hearing. Amongst other things, the Auditor General expressed concern over salary levels at OPG generally, and noted that for many positions at OPG, the average earnings at OPG exceeded the maximum potential earnings for the comparable position in the Ontario public service generally. The Auditor General views the public service as an appropriate general comparator for OPG.

The Board directed OPG to file a comprehensive compensation benchmarking study as part of this proceeding. OPG retained AON Hewitt to prepare this report (the "AON Report"). The AON Report was prepared in late 2011, and updated in 2013. As such it does not include increases in the average compensation for OPG's unionized workers since 2013 (nor any changes at the comparator companies). It covers salary benchmarking for the regulated business (both nuclear and hydroelectric). The AON Report has a section on total cash compensation (which excludes pensions), and a separate section for pensions.

Total Cash Compensation

With respect to total cash compensation, AON considered three comparator groups: Group 1 (power generation, electric utilities nuclear R&D), Group 2 (nuclear power generation and electric utilities), and Group 3 (general industry). The table below summarizes the results for total cash compensation (base salary and short term incentive). It does not include compensation costs related to pensions.

[68] Undertaking J9.7 Attachment 1
[69] Tr Vol 8 page 46

Table 19
Total Cash Compensation
%Differential vs 50th Percentile

%	Group 1	Group 2	Group 3
PWU	20.5	19.1	29.4
Society	-2.9	-3.8	23.3
Management	3.0	-3.4	20.9
	All job families	Admin, Engineering, Environment, Finance, Maintenance, Operations	Admin, Finance, IT, HR, Corporate Services

The AON Report concluded that the PWU is compensated at significantly higher than the 50th percentile for all three groups, whereas the Society and OPG management are compensated at close to the 50th percentile for Groups 1 and 2, and well above the 50th percentile for Group 3. The findings of the AON Report are consistent with evidence filed with the Board in previous proceedings, and OPG stated that it was not surprised by the results of the survey.[70] If PWU salaries were at the 50th percentile, OPG estimates its costs would have been reduced by $96M in 2014 and $94M in 2015.[71]

OPG's position on the AON Report (which was broadly supported by the Society and the PWU) is that although the information is interesting, it does not assist OPG in achieving better results through the collective bargaining process.

OPG presented evidence from Dr. Chaykowski to support its position. Dr. Chaykowski testified that unions typically have a great deal of negotiating power because if negotiations fail they will end up in binding arbitration. Dr. Chaykowski indicated that arbitration decisions are usually favourable to unions. Although arbitrators are supposed to take into account the employer's ability to pay, in Dr. Chaykowski's opinion they usually do not.[72] Arbitrators typically use "patterning" to set salary levels, whereby they compare the situation before them with recent agreements obtained by similar unions in similar industries. Dr. Chaykowski stated that the best comparators for OPG

[70] Tr Vol 8 pages 73-75.
[71] Undertaking J9.11 - This analysis appears to relate to Group 1, as opposed to Group 2. However, the Group 1 and Group 2 placement of the PWU are very similar (20.5% above median for Group 1 and 19.2% above median for Group 2.
[72] Tr Vol 8 page 156.

were Bruce Power and Hydro One, although he conceded different arbitrators might use different (though broadly similar) comparators.[73]

Dr. Chaykowski's evidence highlighted many of the challenges OPG faces in controlling costs in a unionized environment. He also stated that OPG wage settlements generally had been favourable when compared to what he viewed as the appropriate comparators.[74] However, pursuant to the terms of his retainer with OPG, Dr. Chaykowski was not asked to provide an opinion on the specific results achieved by OPG for its current collective agreements. Dr. Chaykowski was also not asked to provide an opinion on the appropriateness of OPG's overall compensation costs.[75]

OPG relies on Dr. Chaykowski's evidence to submit that it could not have achieved better results in its collective bargaining efforts. OPG states that no party has been able to demonstrate what better alternatives were reasonably available to it.

The Board does not accept that the costs arising from OPG's collective agreements – in particular the agreement with the PWU – are reasonable. The compensation package for PWU employees increased from 2010 to 2015 by 19.73%, almost double the 10.35% for the Society over the same time period.

The AON Report demonstrates that OPG compensates the PWU significantly in excess of the industry benchmark. The Board finds that Group 2 is the most appropriate comparator for OPG. Group 2 is a small cohort of nuclear related comparators: Atomic Energy of Canada Limited, Bruce Power, Candu Energy Inc., Hydro Quebec, and New Brunswick Power. All are unionized and have or had, in the case of Hydro Quebec nuclear operations. Three of them, including Bruce Power, which is in fact the comparator OPG prefers, are in Ontario. On average, these companies were able to achieve significantly better results than OPG through their compensation management and collective bargaining efforts with respect to PWU equivalent positions. The Board has no specific information as to how these results were achieved, but the Board does have sufficient evidence to conclude that these similar companies with comparable positions achieved superior results. OPG accepted that, as the Board is not involved in any of its collective bargaining activities, it can only judge the reasonableness of the outcome by examining the final results.

[73] Tr Vol 8 pages 54-56
[74] Exh F4-3-1 Attachment 1
[75] Tr Vol 8 pages 59-60

The Board was assisted by the analysis provided in the AON Report. The Board directs OPG to file a similar, independent, comprehensive compensation study that compares OPG compensation with broadly comparable organizations in the next cost of service application. The study should cover a significant proportion of OPG positions.

The Board does not accept OPG's argument that it should only be compared against successor companies to Ontario Hydro, in particular Bruce Power. OPG provided evidence comparing it with some of the other successor companies to Ontario Hydro, and argued that it had done well in comparison. Even to the extent that these were the only suitable comparators (an idea the Board rejects), the Board is not satisfied with the quality of the comparison conducted by OPG.

OPG provided two comparisons: a comparison of 2013 wage levels between OPG and Bruce Power for certain positions, and a general wage increase comparison between OPG and six Ontario Hydro successor companies from 2001-2012. All of the analysis was conducted by OPG.

For the wage comparison between Bruce Power and OPG, only 12 positions are compared. The positions were selected by OPG. The wage comparison does not include pensions or OPEBs, which are a significant component of OPG's compensation package. It compares only the top band in each category, and does not take into account the number of employees that might be in that band, or in any other band. In addition, the Auditor General discovered that approximately 1,200 unionized staff at OPG were in fact paid more than the maximum amount set out in the salary bands. The comparison presented by OPG does not mention this, and absent the Auditor General's report the Board in all likelihood would not have had this information.[76]

OPG conceded that different comparisons were possible, and that different companies might choose to present the data in different ways. For example, Hydro One had presented a comparison in a recent application which indicated that it had achieved favourable compensation results when compared to OPG.[77] The Board prefers the evidence of an expert third party to the less rigorous analysis conducted by OPG.

[76] When questioned on this topic, OPG responded by undertaking that the correct number was now 972, not 1,200, and that if those 972 employees (who had higher salary on account of grandfathering) were limited by the maximums in the current salary bands the impact would result in annual savings of $5.6M – Undertaking J8.1.
[77] Tr Vol 8 pages 81-85

Pension Costs

Pension costs are a major driver of total compensation costs. OPG proposes to recover $471.3M in 2014 and $405.3M in 2015 for pensions, excluding tax impacts. These amounts include the current service costs under compensation, as well as the pension component of centrally held costs.

OPG's pension plan is very generous. The AON Report benchmarked the employer paid value of OPG's pension versus the comparator group. It concluded that OPG's pensions and benefits are significantly more generous than those of its comparators. The value of OPG's pensions as a percentage of base pay was approximately 33% higher than that of the comparator group. The value of OPG's life insurance benefits and medical and dental benefits were also significantly higher than those of its comparators.[78] These pension amounts are in addition to the total cash compensation analysis referenced above in Table 19 which shows the differential to the 50th percentile.

The OPG pension plan as it is constituted at present requires an employer to employee contribution ratio of at least 3:1.[79] The Auditor General's report indicated that "Since 2005, the employer-employee ratio at OPG has been around 4:1 to 5:1, and significantly higher than the 1:1 ratio at the Ontario Public Service".[80] Board staff and SEC submitted that this ratio is too rich when compared with other plans. Board staff submitted that there is no evidence that this contribution ratio is required for OPG to be competitive in attracting new employees. A 1:1 ratio would reduce pension expense for the regulated business by $60M annually.[81] Board staff submitted that reductions would be $140M if special payments were included. OPG argued that the richness of the plans was the result of Ontario Hydro decisions. OPG was required to adopt collective agreements and the pension plan in 1999. The special payments relate to past service and OPG argued that changes to pension plans can be made only prospectively.
The Board is concerned that no changes were made to pension benefits in the current collective agreements. OPG had a report prepared by Towers Watson in 2011 (updated in 2013) which indicates that, absent significant changes, OPG's current pension plan is unsustainable and risks bankrupting the company.[82] OPG had this

[78] Exh F5-4-1 pages 32-36
[79] The 3:1 figure excludes special payments. If special payments are included the ratio is higher than 4:1.
[80] Exh KT2.4, Annual Report of the Auditor General, page 166
[81] Exh L-6.8-Staff-121
[82] Undertaking JT2.12 Towers Watson CHRC Briefing, December 14, 2011

report during the negotiations for its current collective agreements. Despite this, OPG signed a collective agreement with the PWU that contained no changes to the pension plan.

OPG did not file the Towers Watson report in the arbitration hearing with the Society.[83] It appears to the Board to be highly relevant that the status quo with respect to pensions was (and remains) in danger of bankrupting the company. The arbitration decision includes a lengthy section on OPG's ability to pay for the new agreement, and a section on the appropriate pension contribution. Arbitrator Albertyn concludes that no changes are necessary to the status quo with respect to pension contributions.[84] Despite Dr. Chaykowski's belief that arbitrators pay only "lip service" to a company's ability to pay,[85] the Board is concerned that OPG did not bring this very important report to the arbitrator's attention.

The Board is also concerned that OPG appears to have no concrete plan regarding how it will address the very serious issues raised in the Towers Watson report. Absent some form of intervention by the government, OPG's only solution to the problem appears to be a plan to pass all of the costs on to ratepayers in future proceedings.[86]

SEC submitted that implementation of the potential changes outlined in the Towers Watson report would reduce pension and OPEB costs by $118M annually. OPG argued that the impacts of the potential changes outlined in the report are not additive.

OPG's pension plan is extremely generous and extremely costly. The Board finds that it is not reasonable that all of these costs be passed on to ratepayers. The Board is also concerned that OPG, the largest utility the Board regulates, has a pension plan that appears to be unsustainable, and that very little seems to have been done to address this. The Board does not accept OPG's assertion that the issue of pension costs is beyond its control. The Board finds that OPG should be moving towards a 1:1 employer-employee contribution ratio, and that the 50th percentile for pension costs is the appropriate target, consistent with the Board's findings on wages and salaries. Disallowances for pension and OPEB costs are subsumed in the annual $100M compensation disallowance.

[83] Tr Vol 8 page 155
[84] Exh L-6.8-SEC-106, Attachment 1 pages 20-26, 31-32
[85] Tr Vol 8 page 156
[86] Tr Vol 8 pages 161-162

4.1.3 Other Compensation Issues

The Board is also troubled by a lack of management oversight in some areas, which was noted in the Auditor General's report. Performance reviews of unionized staff, which are supposed to be conducted prior to an employee's advancement through the salary bands, appear to often not occur. In cross examination, OPG's witness stated that there was in fact no formal requirement for performance reviews at all.[87]

The Board also notes the Auditor General's comments in its report with respect to OPG's management of overtime. The Auditor General found that "management of overtime at OPG still required significant improvement" and that in a significant number of cases there was no supporting documentation for overtime approval.[88] This has been identified as an area of poor planning, and thus the Board finds this to be an area of potential improvement in efficiency.

The Board observes the link between OPG's poor performance in the three key metrics of nuclear benchmarking presented in the annual reports based on the ScottMadden methodology (Total Generating Cost, Unit Capability Factor and Nuclear Performance Index), and high staff compensation costs. As described in further detail in the Nuclear OM&A and Benchmarking section, OPG has failed to reach the targets it set for itself in the Total Generating Cost metric. Compensation costs are a major driver of the "costs" side of the Total Generating Cost equation, and OPG's high compensation costs are undoubtedly one of the reasons that it performs so poorly on this metric. OPG's poor productivity – in other words its poor performance on the key "bang for buck" metric – results in significant incremental expense. These are matters that are broadly speaking at least partially within the control of OPG's management, and it is not reasonable to pass all of these costs on to ratepayers.

For illustrative purposes and based on the 2012 OPG nuclear benchmarking report, Board staff estimated the savings if OPG's Total Generating Cost was at the median. Costs would be reduced by approximately $300M per year (Total Generating Cost Differential x production forecast). If OPG were to actually achieve top quartile, the savings would be $725M per year. The Board will not make disallowances even close to these amounts. However poor management controls, and overall productivity are a consideration in the Board's findings.

[87] Tr Vol 8 pages 121-123
[88] Exh KT2.4, Annual Report of the Auditor General, pages 174-175.

4.1.4 Conclusion with Respect to Disallowances to OM&A for Excessive Compensation

The Board disallows $100M in each of 2014 and 2015 due to the finding of excessive compensation. As detailed above, there are several drivers to this finding: excessive salaries (chiefly relating to the PWU), excessive pension costs, too many unionized and management staff, poor performance on the Total Generating Cost metric (which is related to excessive salaries and number of staff), and a lack of management oversight with respect to performance management and overtime.

One of the Board's important functions is to act as a market proxy. Regulation exists to prevent the abuse of monopoly power. Absent regulation, monopoly service providers would be able to pass on any cost to its captive consumers, and there would be little incentive for the provider to exercise cost control or seek efficiencies. The Board finds that it would not be reasonable to pass all of OPG's compensation costs on to ratepayers.

The Board has relied to some extent on the benchmarking evidence before it in making this decision. Benchmarking analysis is commonly used by both the Board and other regulators to assist with the assessment of the reasonableness of a utility's costs or performance. OPG itself recognizes the value of benchmarking, which is shown by its support of the ScottMadden nuclear benchmarking studies. OPG's shareholder is also a supporter of benchmarking: the Memorandum of Agreement between OPG and its shareholder in fact requires OPG to benchmark itself against other electricity generators, and to set performance measures against these benchmarks.

The Board is mindful that benchmarking, while useful, is not a precise tool. It provides a high level picture of OPG's compensation situation, but cannot be expected to produce an exact dollar figure by which OPG's compensation is too high (or, in theory, too low). For this reason, the Board will not simply make disallowances based on a straight mathematical differential between OPG and the 50th percentile of the appropriate benchmark. The Board also understands that there are limits to what OPG can achieve on a year to year basis,[89] and that it has made some progress in recent years. The Board is therefore making disallowances that are significantly less than what the

[89] For example, the Government of Ontario report released on August 1, 2014, *Report on the Sustainability of Electricity Sector Pension Plans* indicates that a reasonable phase-in period for achieving a pension contribution ratio of 1:1 would be 5 years.

evidence could in theory support. The Board believes that, taking all of the factors into consideration, a $100M disallowance per year is a reasonable result.

The table below outlines the areas of concern to the Board and provides an estimate of all the costs associated with each item. Some of these items, such as the historical variance trend for hydroelectric OM&A line, are discussed in more detail in other sections. The Board is not making disallowances in the amounts shown in the chart. Rather, the table is designed to itemize the factors that went into the Board's decision to make the annual $100M disallowance. It is for illustration only, and it is not an exhaustive list of the areas where improved cost control should be achieved – for example OPG's poor performance on the Total Generating Cost metric is not included in the chart. The Board also recognizes that there may be some level of overlap between the categories.

Table 20: Factors Supporting Compensation Disallowance

Reduction in $million		2014	2015	Regulated Business Affected
1	Hydroelectric (historical base and project OM&A trend, budget vs. actual spend)	9.5	9.8	Hydroelectric
2	PWU at 50th percentile (wages only based on the AON report) includes corporate support cost reduction	96.0	94.0	Hydroelectric and Nuclear
3	Pension Cost Reduction (assume reduction to bring to comparable levels as per the AON Report and Towers Watson Report)	60.0	60.0	Hydroelectric and Nuclear
4	Management Reduction to reflect 10.5% management in total staffing – salary impact only	18.2	16.9	Hydroelectric and Nuclear
5	Reduction of 244 staff positions – wage impact only (as per the Goodnight benchmarking study.)	19.8	1.8	Nuclear

Note 1: Section 2.2 of this Decision
Note 2: Undertaking J9.11 and section 4.1.2 of this Decision
Note 3: Exh L-6.8-Staff-121 and Undertaking J9.10
Note 4: Table 18 of this Decision and Undertaking J9.7, 2014: 107.9 Management FTE x $168,297 = $18.2M, 2015: 100.3 Management FTE x $168,408 = $16.9M
Note 5: Undertaking J9.7, Total nuclear FTEs in 2013 less 244 FTEs = 8220.8 FTE, 2014: (8370.3-8220.8) x $131,149 = $19.8M, 2015: (8234.0-8220.8) x $136,918 = $1.8M

The Board recognizes that OPG will have to pay its unionized employees pursuant to the terms of its collective agreements, however the Board finds these costs to be unreasonable, and will not pass them on to ratepayers.

4.1.5 The Court of Appeal's Decision

In the previous OPG payments case (EB-2010-0008), the Board made disallowances in the amount of $145M on account of excessive nuclear compensation costs. This decision was appealed by OPG. The appeal was dismissed at the Divisional Court; however OPG was successful before the Ontario Court of Appeal. The Court of Appeal's decision has now been appealed to the Supreme Court of Canada, and that appeal is expected to be heard in December 2014.

The Court of Appeal held that OPG's test period compensation costs were "committed", and therefore were subject to a prudence review. In conducting a prudence review, the Board was not permitted to use hindsight in assessing the reasonableness of OPG's decisions to commit to the costs: in other words the Board could only use information that was available, or should have been available, to OPG at the time the costs were committed to.

Although OPG refers to its compensation costs as "committed" in its argument, it is not clear exactly what costs OPG believes have been committed to. Although collective agreements are in place for much of the test period, this is only one factor (albeit a significant one) in determining the amounts that OPG will have pay in compensation over the test period. Management costs, staffing levels, overtime costs and other cost drivers are not determined by OPG's collective agreements, and have generally not been committed to.

In the previous proceeding (EB-2010-0008) OPG also referred to its test period compensation costs as being largely "committed." Indeed that was the major issue in its appeals. However, it was revealed in this proceeding that there was in fact significant room for OPG to control compensation costs over the 2011-2012 test years: in 2011 and 2012 OPG's Business Transformation initiative ended up saving OPG almost exactly the $145M disallowed by the Board.[90] OPG's compensation costs are clearly in some measure controllable, and OPG has effectively acted to control them to some degree in the past.

Even to the extent that OPG's 2014 and 2015 compensation costs are "committed", the Board has considered the Court of Appeal's decision and is satisfied that it has taken the decision into account. The Court of Appeal's decision states that the Board cannot

[90] Tr Vol 3 pages 68-69, 134

use hindsight in assessing the prudence of committed costs. Even if one were to accept that OPG's test period compensation costs are entirely committed, the Board is not using hindsight to assess the reasonableness of OPG's collective bargaining practices (or any other compensation costs). All of the evidence relied on by the Board is information that OPG either had available to it when it committed to its compensation costs, or should have had before it.

4.2 Pension and Other Post-Employment Benefits Accounting (Issue 6.8)

OPG's historical and forecast pension and OPEB expenses are summarized in the following table. The current service cost of pension and OPEB is part of compensation while the remainder is part of centrally held costs.

Table 21: Pension and OPEB

	$million	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Actual	Total 2008-13	2014 Plan	2015 Plan
	Pension									
1	Accrual Basis - recoverable in payment amounts	121.4	141.4	150.1	195.0	286.1	383.3		471.3	405.3
2	Cash Basis	198.6	206.1	208.5	235.5	297.1	242.9		321.9	329.6
3	Difference (1-2)	(77.2)	(64.7)	(58.4)	(40.5)	(11.0)	140.4	(111.4)	149.4	75.7
	Other Post-Employment Benefits									
4	Accrual Basis - recoverable in payment amounts	119.2	162.5	161.0	173.2	203.0	231.3		204.6	212.8
5	Cash Basis	44.2	43.1	43.4	48.4	57.9	61.2		89.6	95.8
6	Difference (4-5)	75.0	119.4	117.6	124.8	145.1	170.1	752.0	115.0	117.0

Source: Chart 4 AIC, JT2.40, J9.6, Exhibit N2
2008-2013 excludes newly regulated hydroelectric
Note 1: The source for the 2015 and 2014 cash basis is J9.6

For 2014 and 2015, OPG proposes rate recovery of its pension and OPEB costs based on the accrual method of accounting: $1,294M in total. As noted in lines 1 and 4 of Table 21, in 2014, $471.3M would be recovered for pensions and $204.6M would be recovered for OPEBs. In 2015, $405.3M would be recovered for pensions and $212.8M would be recovered for OPEBs. The accrual basis recognizes these expenses when the entitlement to pension and OPEB is earned, not when OPG actually has to pay them out.

SEC submitted that pensions and OPEB recovery should be determined on a cash basis. CME, CCC and LMPA supported SEC's submissions to use the cash basis for rate recovery. The cash basis recognizes the expense when cash payments are made, as opposed to the accrual method in which the expense includes future liabilities. In theory, over time, the accrual and the cash method should result in the exact same amount of total expense.

Board staff supported use of the cash method for pensions and the accrual method for OPEBs, provided that OPG be directed to set up an irrevocable trust or fund for the recovery in excess of OPEB cash requirements. In the absence of a set-aside mechanism, Board staff supported the use of the cash basis for both pensions and OPEBs.

For tax purposes, a tax liability is created on OPG's corporate financial statements when the accrued expense exceeds the cash expense. Including an amount to recover the tax liability associated with higher accrued expenses increases the proposed revenue requirement. Parties submitted that adopting the cash method would reduce the proposed revenue requirement by $609.4M in 2014 and 2015, not just the $457.1M[91] difference between the cash and accrual expenses because of the decreased tax recovery amount.

There is currently no consistency among utilities in the use of either cash or accrual method for rate recovery of pension and OPEB costs. Both methodologies have been approved by the Board. The Board has approved OPG's payment amounts based on the accrual method since EB-2007-0905, the first cost of service proceeding. OPG indicated that the majority of regulated entities use the accrual method. OPG submitted that the Board should consider the accounting and ratemaking treatment of pensions and OPEB as part of a generic proceeding. Until the generic proceeding is concluded, OPG proposed the Board maintain the accrual method for determining payment amounts.

Board staff submitted that the cash basis for pension and OPEB determination has been more stable and will continue to be more stable than the accrual basis which is significantly affected by discount rates. OPG replied that there is no basis for claims or predictions on the magnitude or direction of the difference between the cash and accrual method.

[91] Sum of 2014 and 2015 for lines 3 and 6 of Table 21

Based on review of 2008 to 2013 data, Board staff determined that OPG has been authorized to collect $752M more in OPEB and $111.4M less in pension expenses than OPG has been required to pay out. Board staff submitted that OPG has used this over-collection for general corporate purposes, and that the money has not been set aside to cover the costs when they actually come due at some point in the future. Board staff submitted that the historical over-collection of $752M could be used to offset the regulatory liability for future OPEB costs.

Extrapolating the 2014-2015 trend, Board staff estimated OPG could over-collect $1.2 billion in OPEB expenses within the next 10 years. OPG's witnesses agreed that cash amounts would likely be less than accrual amounts for the next 10 years for OPEBs, but disagreed with Board staff's estimate of $1.2 billion in over collection.

OPG characterized Board staff's suggestion that the $752M difference between the cash and accrual methods be used to offset future cash expense as a claw back. OPG argued that the cash flow generated from payment amounts is spent as OPG determines. In addition, there is no link to the pension and OPEB costs approved in payment amounts to what OPG ultimately spends.

OPG argued that if the cash basis is used for ratemaking, it would ultimately be required to increase its borrowings. Ratepayers would be required to pay for that debt and OPG's financial ratios would be affected.

OPG indicated that USGAAP requires the use of accrual accounting for pensions and OPEB to be used in its corporate financial statements, and that if recoveries from ratepayers were on a cash basis, OPG would not be able to record the difference as regulatory assets. Board staff noted that Hydro One, which also reports under USGAAP, recovers pension expense on a cash basis with no apparent conflict with USGAAP.

Board staff submitted that the Board could consider the cash basis for pension and OPEB for the test period pending a generic proceeding on pension and OPEB costs and recovery mechanisms.

Board staff submitted that if the Board were to approve recovery based on the cash method a new variance account would be required, since OPG has the discretion to contribute more than the minimum amount determined by its actuary to the pension plan. The variance account would enable the tracking of any additional cash contributions made by OPG to be considered in the future for recovery.

OPG submitted that the determination of pension and OPEB expense was not an issue on the issues list and that OPG did not file expert evidence on the matter, nor did any other party. In OPG's view, the matter is very complex and best suited to a generic proceeding.

Fund or Irrevocable Trust for OPEB

While OPG makes contributions to a registered pension plan, there is no equivalent plan for OPEB. The accrual amounts are determined by OPG's actuary and used in OPG's corporate financial statements as required under USGAAP. OPG's actuary also determines the minimum cash requirements for its pension and OPEB plans based on legislation and regulations.

Board staff submitted the Board could approve the accrual method for OPEB on the condition that OPG establishes a set-aside mechanism, such as an irrevocable trust or fund for OPEB, similar to what was referred to the in the Federal Energy Regulatory Commission's Statement of Policy report PL93-1-000.[92] Board staff also submitted that if the Board had any reservations about a fund or trust, the Board could limit recovery of OPEB expense as determined by the cash method, or OPG's out-of-pocket test period costs. OPG submitted that the Board has no jurisdiction to order OPG to set up an irrevocable trust or fund. OPG argued that the matter is complex and submitted that a segregated fund could be considered as part of a generic proceeding.

Board Findings

The Board will only allow OPG to recover its cash requirements for pensions and OPEBs in 2014 and 2015, approving a revenue requirement of $836.9M for pension and OPEB.

The Board will reduce the total proposed amount to be recovered in rates by $457.1M, which is a reduction of $225.1M in proposed pensions and $232.0M in proposed other

[92] Exh K13.2, FERC PL63-1-000, Post-Employment Benefits Other Than Pensions, Statement of Policy, December 17, 1992

post-employment benefit amounts.[93] OPG's most recent actuarial valuation as at January 1, 2014 by AON Hewitt was filed in evidence.[94] The Board relies on the AON Hewitt valuations of the cash requirements in 2014 and 2015 and sets OPG's payment amounts accordingly.

In addition, the Board approves the establishment of a new deferral account to record the differential between the accrual and cash valuations for pension and OPEB expenses. The Board's reasons follow in the sections below.

OPG and some parties suggested that the Board hold a generic hearing to review pension and OPEB costs. The Board agrees and believes that a generic proceeding on the regulatory treatment and recovery of pension and OPEB costs would be beneficial. A generic proceeding could enhance understanding of the different rate making options, establish policy and decide on how best to apply that policy to OPG and other Board-regulated entities. Transition to a different accounting treatment of pensions and OPEBs for OPG, if required, would be addressed by the Board in OPG's next cost of service proceeding, having been informed by the outcomes of the generic proceeding.

The Board is not necessarily permanently moving from an accrual to a cash basis for setting OPG's payment amounts. The Board is providing OPG with sufficient revenue to fund its cash needs for 2014 and 2015 until a comprehensive review of pensions and OPEB is undertaken through a generic proceeding. The Board is concerned that any money collected from ratepayers today, in excess of the cash requirements, is not being used to fund future pension and OPEB cash requirements. The Board has considered both OPG's needs and those of ratepayers. In the absence of a Board policy, the Board will not allow the collection of funds from ratepayers in 2014 and 2015, of an amount higher than OPG's cash needs, when OPG's use of the excess funds is not understood, and the benefit to ratepayers is uncertain.

Until Board policy is established, the Board approves a new deferral account to record the differential between the accrual and cash valuations for pension and OPEB expenses. Based on the policy outcome of the generic proceeding, a future panel will decide on the appropriate disposition (if any) of the deferral account balance.

[93] Undertaking J9.6 states that the 2015 pension requirement on a cash basis is $329.6M. Correcting the 2015 pension requirement on a cash basis in Chart 1 of undertaking J13.7 results in a, accrual vs cash difference of $457.1M.
[94] Undertaking J9.6

At this time, the scope of the generic proceeding is unknown. For clarification, the Board is not setting aside the difference between the cash and accrual amounts for this test period, for purposes of another future prudence review of these costs. The 2014 and 2015 payment amounts will be final in that respect. Any future treatment regarding the deferral account would be limited to the outcomes of the generic proceeding as they relate to the accounting or mechanics of recovery, as applicable.

The application indicated a differential amount of $457.1M based on the 24-month period in 2014 and 2015. However, the $457.1M will be subject to change given the approved effective dates of the payment amounts and OPG's final actuarial evaluations at the end of 2014 and 2015.

OPG indicated that the determination of pension and OPEB expenses for ratemaking was not an issue on the issues list. The Board agrees that the exact words "accounting methods for ratemaking" were not on the issues list. However, the issue was raised in numerous interrogatories and extensively during the pre-hearing technical conference and the oral phase of the hearing. In addition, every proposed expense, particularly material expenses of $1,294M, must be reviewed by the Board to order to determine OPG's payment amounts.

OPEB Costs

Board staff submitted that historical over collection of OPEB expenses should be used to offset the regulatory liability for the future. OPG submitted that Board staff's proposal amounts to a "claw back". The Board does not agree with OPG's characterization and the use of the term "claw back". The amount and use of any excess collected to date from ratepayers must be clearly understood and resolved before the Board allows any further collection in excess of requirements in 2014 and 2015.

On a prospective basis, Board staff estimated that maintaining accrual accounting for ratemaking would result in an over-collection in OPEB revenue of $1.2 billion every 10 years. OPG took issue with Board staff's $1.2 billion estimate. OPG's witnesses indicated a cash flow analysis had been completed, yet were unable to provide any specifics, stating it would be "likely in the next 10 years"[95] before actual OPEB cash payments would exceed the accrual expense. The Board does not find OPG's answer sufficient. The Board has little evidence by which to understand the magnitude or

[95] Tr Vol 13 page 134

duration of the potential over collection of OPEB costs from ratepayers, but the prospective numbers are alarming.

The Board is not confident OPG has undertaken the level of cash flow analysis required to ensure it will have sufficient cash available as a corporation, when its cash needs exceed accrued expenses. It would be inappropriate to collect revenues today in excess of cash requirements and then turn to ratepayers in the future, when cash requirements exceed accrued expenses. The Board must ensure ratepayer interests over time are fully considered.

Pension Costs

From 2008-2013 cash funding requirements for pensions exceeded accrued expenses by $111.4M; the opposite of OPEB costs. However, in 2014 and 2015 accrued pension expenses exceed cash funding requirements by $149.4M in 2014 and $75.7M[96] in 2015.

With accrued pension expenses exceeding cash requirements in 2014 and 2015, the Board's concerns relating to OPEB costs regarding the magnitude and duration of over collection and the associated cash flow analysis apply equally to pension costs.

Prior Board Decisions

The Board is directing the use of the cash basis of recovery for 2014 and 2015. This is different from prior OPG decisions. In OPG's last cost of service proceeding, EB-2010-0008, the Board found no compelling reason to change OPG's approach of using the accrual method. The Board noted that consistency in accounting treatment which allows comparison of year-over-year results to be advantageous for assessing reasonable cost levels.

This panel agrees with the EB-2010-0008 decision as consistency is desirable in order to compare these costs. However, in this case the benefits of consistency are outweighed by the concern regarding the significant increase in payment amounts to recover accrued expenses. In 2011 and 2012, the accrued expenses for pensions were $195.0M and $286.1M respectively. In 2014 and 2015, the forecast accrued expenses are almost double at $471.3M and $405.3M.

[96] After adjusting the cash contribution number in 2015 to the amount shown in J9.6 of $329.6M.

In reply submission, OPG indicated that while the figures may be different from its last cost of service proceeding in EB-2010-0008, "the circumstances have not changed". The Board disagrees. The circumstances have changed as the accrued expenses are increasing and volatile, dependent upon the assumptions adopted by OPG's management, such as the appropriate discount rate. Volatility in the test years was evident when OPG filed its Exhibit N1 impact statement in December 2013, months after filing its Application. After updating the discount rate and mortality rate assumptions applied to its pension plan, accrued expenses in 2014 and 2015 increased, exceeding OPG's materiality threshold and increasing the proposed revenue requirement by $142.3M. This was followed by the Exhibit N2 impact statement filed in May 2014, which based on higher discount rates for the pension plan, decreased the revenue requirement by $278.7M.

Implications of Cash Method

OPG submitted that the cash basis would ultimately require OPG to increase its borrowings and ratepayers would have to pay for that debt. In addition, the cash basis would affect financial ratios. The Board has approved OPG's capital expenditures and rate base for 2014 and 2015. The payment amounts include a weighted average cost of capital. In addition, every cost that OPG requires to recover to run its business and the opportunity to realize its regulated rate of return, underpins the payment amounts. The Board does not understand what additional borrowing would be required to fund the regulated side of OPG's business.

OPG prepares its financial statements in accordance with USGAAP, which requires pensions and OPEB costs to be determined on the accrual method. In reply argument, OPG identified corporate financial reporting issues such as qualified audit opinions and the recognition of existing regulatory assets if the Board were to utilize the cash basis for ratemaking while its corporate financial statements were based on the accrual method. The issue of cash versus accrual is one of timing. This Board does not regulate financial reporting requirements, but is confident OPG's management, its Audit Committee and external auditors will reflect the outcomes of this Decision in its financial statements.

Given the Board's position on these matters, the additional information provided by OPG in its reply argument regarding its discussions with Ernst & Young LLP was not helpful to the Board. As an aside, however, the Board also notes that it is not generally appropriate to file “new evidence” following the closing of the evidentiary portion of the proceeding.

Pension and OPEB Cost Variance Accounts

OPG has the ability to contribute additional funds to its pension plan in excess of the minimum cash requirements to reduce its unfunded liability. The Board recognizes this opportunity and does not want to dissuade OPG from contributing more than the cash amounts approved in its payment amounts. The total unfunded liability on OPG’s corporate balance sheet was $5,469M as of December 31, 2013: a pension deficit of $2,461M; a supplementary pension plan deficit of $289M; and OPEB deficit of $2,719M. In addition, AON Hewitt determined the pension plan had a small solvency deficit on January 1, 2014, which will require additional funds to eliminate.

The Board will use its available ratemaking tools so as to not discourage OPG from making additional contributions, in addition to its minimum cash requirements, to decrease its unfunded liability without financial hardship. The Board approves a new variance account to track any contributions that differ from the minimum cash requirements, as included in the 2014 and 2015 payment amounts. Interest will apply to this variance account given that it relates to cash payments.

In addition, the Board has approved the establishment of a new deferral account to track the differential between the accrued and cash valuations for pensions and OPEBs. The Board approves the accrual of interest on the variance account balance related to additional cash contributions made, but does not approve the accrual of interest on the deferral account balance given that it tracks non-cash items. This treatment is consistent with OPG’s current variance account based on the accrual method.

Given the effective date for OPG’s 2014 and 2015 payment amounts, the current payment amounts which include accrued pension and OPEB expense will remain in place until November 1, 2014. Correspondingly, the current Pension and OPEB Cost Variance Account will operate until that date to track variances from actual to forecast accrued expenses. After the effective date, the new variance account will be used to track variances from actual to forecast cash expenses. The new deferral account will capture initially the differences between cash and accrual pension and OPEB amounts included in evidence commencing with the effective date. The deferral account balance should be adjusted for future actuarial valuations and actual cash payments on an annual basis until considered by the Board.

4.3 Corporate Support Costs

(Issue 6.9)

OPG is structured such that certain corporate groups provide services and incur costs in support of the hydroelectric and nuclear businesses. Corporate groups include Business and Administrative Services, Finance, People & Culture, Commercial Operations & Environment, and Corporate Centre. OPG is asking for approval of corporate support costs, which are $505.8M in 2014 and $483.9M in 2015.

As shown in Table 5 (to a minor extent),Table 13 and the following table, corporate support costs have increased significantly over the 2011 - 2013 period due to the implementation of a centre-led organization driven by the Business Transformation initiative.

Table 22: Corporate Support Costs

$millions	2010 Plan	2010 Actual	2011 Approved	2011 Actual	2012 Approved	2012 Actual	2013 Budget	2013 Actual	2014 Plan	2015 Plan
Nuclear	247.0	226.5	249.2	233.1	450.3	408.4	451.0	428.3	433.9	417.4
Previously Regulated HE	25.1	22.4	24.8	22.0	29.0	24.5	29.7	26.1	29.8	26.9
Newly Regulated HE							38.8	35.2	42.1	39.6
Total	272.1	248.9	274.0	255.1	479.3	432.9	519.5	489.6	505.8	483.9

Source: Exh F3-1-2 Tables 1,2,3 Exh F3-1-1 page 2 and 3, Exh L-1-Staff-2

Board staff observed that many of the corporate support functions are what AON Hewitt would compare with “general industry”. The AON Hewitt National Utility Survey indicated that the general industry comparable jobs are significantly overpaid by OPG by about 20 to 29% versus P50 (the 50th percentile). The Auditor General’s analysis of administration, finance and human resources jobs indicated that the majority of these jobs are overpaid at OPG as compared with the Ontario Public Service. The Auditor General also observed that the Goodnight benchmarking found that nuclear support functions were generally overstaffed while nuclear operational functions were generally understaffed. OPG replied that it is bound by collective bargaining and committed costs cannot be reduced.

OPG has access to raw cost data from EUCG for the information technology function and Electric Utility HR Metrics Group for the human resources function. OPG prepares benchmarking reports from this data, but there is no independent benchmarking analysis. Board staff observed that the last independent benchmarking study of the finance function was conducted in 2010 based on 2008 data. Board staff submitted that independent benchmarking of the corporate support function is required given the significant changes resulting from Business Transformation. The analysis would need to be normalized and reflect the period before and after Business Transformation.

The 2011 information technology and 2012 human resources benchmarking results prepared by OPG indicate that OPG is not performing in the top quartile with respect to cost. Board staff submitted that test period OM&A reductions would be appropriate. However, OPG argued that the submission did not recognize the benefits that OPG achieved in the contract with its information technology service provider and that the Board staff interpretation of the human resources benchmarking was not appropriate.

Given the consistent over-forecasting, Board staff submitted that a $25M reduction to nuclear OM&A was appropriate. LPMA determined that the previously regulated hydroelectric facilities corporate support costs were 11.7% over-forecast in the 2010 to 2013 period and proposed reductions of $8.4M in 2014 and $7.8M in 2015. On the basis of 7.2% over-forecasting in the historical period, LPMA proposed reductions of $31.2M in 2014 and $30.1M in 2015 for nuclear corporate support costs. SEC submitted that OPG corporate support costs should be reduced by $35M in each of the test years on the basis of historical over-forecasting and benchmarking results. OPG argued that all of these submissions should be rejected as they do not address the evidence in relation to the test period costs, or consider the reasons for the historical variances.

Board Findings

OPG introduced the Business Transformation initiative in 2011 and implemented the centre-led organization in 2012. The Board acknowledges the impact of OPG’s Business Transformation initiative on the number of staff, including corporate support staff. Efficiencies should be achieved and duplication reduced with the organization for corporate support functions.

In addition, the Board acknowledges OPG's commitment to proceed with an open competition for the next IT service contract[97] as a positive step, however any cost savings will not impact the test period.

The Board finds the Goodnight nuclear staffing analysis was informative for this proceeding. While corporate support functions were reviewed by Goodnight, only corporate support dedicated to the support of nuclear operations was considered.

The Board finds the internal benchmarking analysis undertaken by OPG based on the raw cost data from EUCG for the information technology function and Electric Utility HR Metrics Group for the human resources function to be inadequate. The human resources benchmarking is based on 2012 data, the information technology benchmarking was based on 2011 data and no recent benchmarking was filed for the finance function. Efficiency gains in the corporate support functions are not apparent in the benchmarking information that OPG has filed with the application.

Parties indicated that OPG has historically forecast higher corporate support costs than it actually spent. The Board finds it difficult to draw conclusions from the historical variance analysis as provided in evidence, as the underlying numbers are affected by employee migration to centre-led functions as a result of Business Transformation. Corporate support costs have increased significantly over the 2011 to 2013 period, but it is not clear to the Board that there has, or will be, an off-setting reduction in the other business units as a result of OPG's centre-led restructuring.

The Board made a disallowance of $100M to OPG's OM&A proposed budgets for 2014 and 2015 for overall compensation, which includes employees in corporate support functions. The Board will not make a further reduction related to corporate support costs.

The Board directs that an independent benchmarking study be undertaken of corporate support functions and costs given the significant changes resulting from the Business Transformation initiative. The results of this study will need to be shown in a manner that facilitates transparent comparison before and after Business Transformation.

[97] Technical Conference Tr April 23, 2014, page 138

4.4 Centrally Held Costs

(Issue 6.10)

Centrally held costs are company-wide costs recorded centrally. They are:

- Pension and OPEB costs not directly included in business unit costs
- Insurance
- Performance incentives
- IESO non-energy charges
- Other – labour related costs, ONFA guarantee fee, business claims and settlements

Pension and OPEB costs are discussed in the Pension and OPEB Accounting section of this Decision. Performance Incentives are discussed in the Compensation section. There were no submissions on the other components of centrally held costs. The Board approves OPG's test period proposed expense for centrally held costs other than pension and OPEB and performance incentives.

4.5 Asset Service Fees and Other Operating Costs

(Issues 6.14 and 6.15)

Service fees for centrally held assets, e.g. OPG head office, are charged to the regulated and unregulated businesses. No submissions were filed on the matter.

The Board approves the proposed asset service fee amounts of $1.5M and $1.7 M for the previously regulated hydroelectric facilities, $2.9M and $3.0M for the newly regulated hydroelectric facilities and $23.3M and $26.8M for the nuclear facilities for the years 2014 and 2015 respectively.

In deriving the asset service fees OPG followed the methodology accepted by the Board in EB-2010-0008. The increases over the test period have been sufficiently explained and are reasonable. The allocation to each of the businesses is approved.

4.6 Depreciation

(Issues 6.11 and 6.12)

There were two key issues to be considered in respect of depreciation: first, the appropriate method for the determination of service life and second, the appropriate service life for the Niagara Tunnel.

As directed by the Board in EB-2010-0008, OPG filed an independent depreciation study undertaken by the consultant Gannett Fleming.[98] An updated study was filed to account for recent material changes, e.g. the Niagara Tunnel Project.[99]

The Gannett Fleming study was based on the average life group method which applies a common life estimate to each of the asset vintages and each of the assets within each vintage. Board staff submitted that OPG should be directed to file another independent depreciation study using the equal life group method which segregates assets into groups of assets with the same life expectancy and plant-life statistics are derived from the group's estimated survivor curve. OPG submitted that the Board should reject that submission. Gannett Fleming's position is that while the equal life group method is superior, there is insufficient information in the case of OPG's assets to apply this method. The Gannett Fleming report also noted that other regulated utilities, e.g., Enbridge Gas Distribution and Union Gas use the average life group method.

OPG submitted that it would be too costly to develop the data to support the equal life group method, and that it is impractical and potentially impossible to do so.

Submissions were also filed on the service life of the Niagara Tunnel. Gannett Fleming recommended 95 years. It was not apparent from the Gannett Fleming studies that the useful lives of the two existing tunnel linings (Sir Adam Beck) were actually 120 years. In an interrogatory response,[100] OPG informed the Board that in 1999 it had extended the useful lives of these assets. As the Sir Adam Beck tunnels have been in-service for close to 60 years and have an assumed useful life of 120 years, Board staff submitted that the Niagara Tunnel should be expected to have a service life in the range of 125 to 150 years, and that a mid-point of 135 years would be a reasonable estimate given the advanced technology and materials used for its construction. LPMA proposed 138

[98] Exh F4-1-1 Attachment 1
[99] Exh F5-1-3
[100] Exh L-6.12-Staff-160(e)

years and SEC proposed 150 years. OPG argued that there was no evidentiary basis for the proposals of the parties.

Board Findings

The Board finds that OPG responded appropriately to the direction in EB-2010-0008 by having an independent depreciation study undertaken. The Board accepts the study results, predicated on OPG's continued application of the average life group method. The Board will not require OPG to file another study using the equal life group method, as the data is not available. The Board accepts Gannett Fleming's evidence that OPG lacks the necessary data to use the equal life group method and the cost to develop the data would be prohibitive.

OPG's depreciation and amortization expense for the test period incorporates all the recommendations made by Gannett Fleming. The Board accepts the evidence of Gannett Fleming and its recommended 95 year useful life for the Niagara Tunnel. Although the useful lives of the Sir Adam Beck Tunnels are longer than 95 years, the useful lives were reviewed and extended after 45 years in-service. The Board will not consider extending the useful life of the Niagara Tunnel at this time.

The Board approves the depreciation expenses as filed to be included in the calculation of the payment amounts.

4.7 Taxes

(Issue 6.13)

OPG seeks approval for property taxes of $16.3M in 2014 (assuming full year for the newly regulated hydroelectric facilities) and $16.8M in 2015 for the regulated business. No submissions were filed on property taxes, and the Board approves OPG's request.

OPG uses the taxes payable method for determining regulatory income tax for the regulated facilities. The tax is allocated based on each business's regulatory taxable income. OPG seeks approval of income tax expense of $187.9M in 2014 (assuming full year for the newly regulated hydroelectric facilities) and $123.7M in 2015 for the regulated business.

This section addresses two sub-issues relating to a tax loss carry-forward from 2013 and deferred taxes associated with the newly regulated hydroelectric assets.

4.7.1 Tax Loss Carry-Forward

In 2013, OPG incurred a regulatory tax loss of $211.6M that OPG attributes to a shortfall in nuclear production. OPG submitted that the associated tax loss carry-forward that was created should not be applied to regulatory taxable income in 2014 to reduce the tax provision included in the payment amounts. OPG argued that OPG's shareholder incurred the costs associated with the loss in 2013 and should receive the benefit of the resulting tax loss carry-forward in 2014. As a result, OPG posted an accounting entry to its corporate retained earnings, to the benefit of its shareholder. OPG relied upon a principle that "benefits follow costs" as stated in the *Accounting for Public Utilities*, published in the United States in 2005 to support its proposal.

> …if ratepayers are held responsible for costs, they are entitled to the tax benefits associated with the costs. If ratepayers do not bear the costs, they are not entitled to the tax benefits associated with the costs.[101]

OPG also referred to two prior decisions in which the Board referenced this principle, namely the OPG EB-2007-0905 decision and the Great Lakes Power EB-2007-0744 decision. In OPG's submission, the situation in 2013 is similar to the situation in 2007 when it incurred a tax loss and the Board did not approve the associated tax loss carry-forward for determining OPG's 2008 payment amounts.

OPG also argued that the Board cannot adjust rates in a future period without a deferral or variance account, as this would amount to retroactive ratemaking.

Board staff submitted that the tax loss should be carried forward and applied to the test period tax provision to the benefit of ratepayers. OPG's payment amounts that were in effect in 2013, when the tax loss occurred, included a recovery amount for income tax. The 2013 payment amounts were established based on the 2011 and 2012 test period and included recovery of approved income tax amounts of $60.9M and $91.1M respectively. The payment amounts approved for 2011 and 2012 persisted into 2013 as OPG did not apply for new 2013 payment amounts. Board staff submitted that since

[101] Accounting for Public Utilities, by Robert Hachne and Gregory Aliff, Part V, Chapter 7, September 17, 2005

ratepayers have borne the tax costs included in the payment amounts in 2013, the 2013 regulatory tax loss carry-forward calculated by OPG should be used to reduce regulatory taxable income in 2014.

Board staff submitted that this treatment is consistent with the Board's long-established policy requiring tax loss carry-forwards to be applied to reduce regulatory taxable income, as stipulated in the 2006 Electricity Distribution Rate Handbook.[102] At the hearing, Board staff cited several Board examples of electricity distributors in their rate applications carrying forward income tax losses from a prior year(s) to reduce or eliminate taxable income in a future year's test period. In addition, Board staff cited several Board decisions approving tax loss carry-forwards to reduce regulatory income taxes.

LPMA and CME supported Board staff's submission.

SEC supported Board staff's submission yet also referred to the "benefits follow costs" principle which was used by the Board in OPG's first payment amount decision (EB-2007-0905). SEC submitted that the "benefits follow costs" principle was used by the Board to ensure that there was a principled way of allocating costs and benefits to regulated and unregulated periods, which was not the case for OPG in 2013. In this case, the loss arose during a period in which OPG was collecting regulated rates from ratepayers. That is a similar situation to the electricity distributors, who do have to apply tax loss carry-forwards in one regulated year to reduce taxable income in subsequent regulated years.

SEC submitted that the "benefits follow costs" principle was never intended to allow a utility to collect money from ratepayers for PILs, then keep that money for their own purposes because they were unable to operate the regulated business at a profit.[103]

In reply, OPG argued that Board staff incorrectly applied the principle in its submission and SEC fundamentally misunderstood the Board's application of the principle. OPG asserted that the tax loss arose because of an operating loss. As OPG and its shareholder had to bear the operating loss, not ratepayers, OPG submitted that its shareholder is entitled to receive the benefit of the associated tax loss.

[102] 2006 Electricity Distribution Handbook, May 11, 2005, page 61
[103] SEC Final Argument page 72

Board Findings

The Board directs OPG to reduce its 2014 income tax provision to recognize and carry forward its regulatory tax loss in 2013. This finding is consistent with Board policy as indicated in the Board's 2006 Electricity Distributor's Rate Handbook (the "Handbook") and in subsequent Filing Requirements.[104] The Board understands the policies contained in the Handbook and the Filing Requirements apply to electricity distributors, not directly to OPG as an electricity generator, yet finds that the underlying Board policy should be applicable to OPG in this application.

The rate regulation of the electricity distribution sector shows a history of tax loss carry-forwards being routinely used in the rate setting process for distributors. This approach is completely consistent with Board policy for tax losses to be applied to reduce income tax to be included in rates, and there is no reason for OPG to be treated any differently in this instance.

OPG referred to two decisions in which the Board did not apply the policy, namely OPG's EB-2007-0905 decision and Great Lakes Power's EB-2007-0744 decision. The Board finds that the circumstances in these two cases were unique and are not comparable to OPG's current circumstances.

The Board's findings in the EB-2007-0905 decision address the fact that OPG was not regulated by the Board prior to 2008, when the tax loss occurred. The Government set OPG's rates in 2005, 2006 and 2007. The Board's EB-2007-0905 decision in 2008 did not reference the policy in the Handbook. The Board finds that the circumstances in OPG's first payment amounts proceeding were unique and the Board's finding in that case resulted from the absence of information and the Board's uncertainty regarding OPG's tax calculation.

> The Board is not convinced that there are any "regulatory tax losses" to be carried forward to 2008 and later years, or if there are any, that the amount calculated by OPG is correct….The Board does not have the information necessary to determine the tax benefits which should be carried forward to offset payment amounts in 2008 or later periods.[105]

[104] A requirement to identify any loss carry-forwards and when they will be fully utilized has been included in the Board's Filing Requirements for electricity distributors' cost of service applications since 2012. With the issuance of the 2012 Filing Requirements (for 2013 rates), the Board included any remaining relevant sections of both the 2000 and 2006 Electricity Rate Handbooks.
[105] Decision with Reasons, EB-2007-0905, pages 169-170

The circumstances in the Great Lakes Power EB-2007-0744 proceeding were unique as Great Lakes Power Limited conducted both regulated and non-regulated businesses. The Board's decision addressed the fact that the corporate tax loss carry-forwards arose due to losses in Great Lake Power Limited's non-regulated businesses. The Board referred to the "stand-alone principle" and that it would be inappropriate for regulated service rates to be affected by the income or loss of a non-regulated business.[106]

> It would be fundamentally unfair to take such tax losses into account when setting rates for regulated service. To abandon the stand-alone principle in this case would give rise to the inappropriate result that rates for regulated service would be affected by the income or loss of a non-regulated business.

OPG's circumstances in 2013 are distinct from the two referenced Board decisions. In 2013, when OPG's tax loss arose, OPG was regulated by the Board and there is no evidence filed to indicate the tax loss was related to OPG's non-regulated businesses. To the contrary, the first line of OPG's reply argument under the Loss Carry-Forward section heading states that the $211.6M regulatory tax loss in 2013 was due to a shortfall in nuclear production.

OPG made a decision to maintain its (then current) payment amounts for 2013. OPG decided not to apply to the Board to change its payment amounts for 2013 based on updated information, including an updated nuclear production forecast. The fact that OPG incurred a tax loss was a risk OPG decided to take on its own accord and should not change the application or treatment of the Board's tax loss carry-forward policy.

In addition, even if one accepted the argument that the circumstances of these prior cases were similar to OPG in 2013, the Board continued to apply the Handbook's policy to electricity distributors after both of those decisions were issued.[107] Accordingly, the Board does not consider either case to have set a precedent. Further, it is apparent to the Board from the submissions of OPG and the parties that the "benefits follow cost" principle has been interpreted differently by the parties.

[106] Decision and Order, EB-2007-0744, Great Lakes Power, pages 40-41
[107] Decision and Order, EB-2008-0322, Hydro One Remote Communities, page 10, Decision and Order, West Perth Power and Clinton Power Corporation, EB-2009-0262/EB2010-0121, page 22

OPG argued that application of the policy would result in retroactive rate making during the term of a final rate order without a deferral or variance account. The issue before the Board is a tax loss carry-forward. The tax loss is carried forward to a subsequent year by definition. The question in this application is whether OPG's shareholder or its ratepayers receive the future benefit, the opportunity to reduce a future year's tax provision by the amount of the tax loss from a prior year.

The Board does not find there to be an issue with retroactive rate making in the context of tax loss carry-forwards in this case. The Board policy was established in 2005 and it has been applied in subsequent years. The Board's Handbook policy did not and does not require the establishment of a deferral account. Therefore, there is no issue of retroactive ratemaking in the Board's view.

4.7.2 Deferred Tax

The December 31, 2013 audited financial statements indicate $181M in deferred income taxes for the newly regulated hydroelectric facilities. OPG submitted that the deferred income taxes on OPG's December 31, 2013 financial statements is to be excluded from the revenue requirement impacts associated with regulating the newly regulated hydroelectric assets. The deferred tax is related to pension and OPEB expense recognition and higher capital cost allowance that is allowed for tax purposes compared to OPG's accounting depreciation.

The Board is required to accept the assets and liabilities of the newly regulated hydroelectric facilities as set out in OPG's December 31, 2013 audited financial statements. This requirement is set out in O. Reg. 53/05, section 6(2)11 part ii

> The Board shall accept the values for the assets and liabilities of the generation facilities referred to in paragraph 6 of section 2 as set out in Ontario Power Generation Inc.'s most recently audited financial statements that were approved by the board of directors before the making of that order. This includes values relating to the income tax effects of timing differences and the revenue requirement impact of accounting and tax policy decisions reflected in those financial statements.

SEC submitted that the $181M net tax liability has been charged as an expense by OPG prior to January 1, 2014, but has not actually been paid yet. SEC disagrees with OPG's proposal which would require ratepayers to pay for tax costs in the future, tax costs incurred prior to the regulation of the newly regulated hydroelectric facilities. SEC submitted that would result in retroactive ratemaking and would be unfair to ratepayers. SEC noted that the Board has never determined that it is appropriate to allow recovery of tax expenses in rates when the taxes were incurred prior to regulation by the Board.

SEC submitted that there is nothing in O. Reg. 53/05 to indicate that the government intended the Board to allow OPG to collect pre-2014 tax expenses from ratepayers in 2014 and beyond. SEC submitted that if the government had intended to require the Board to adopt such a rule, it would have been explicit.

LPMA and CME supported SEC's submissions.

OPG argued that SEC has not considered the entire provision of section 6(2)11 of O. Reg. 53/05. OPG submitted that the wording explicitly provides that the Board, in making its first order, must accept the assets and liabilities approved by the board of directors, including values relating to income tax timing differences and the revenue requirement impact of accounting and tax policy decisions.[108] As deferred tax liabilities relate wholly to income tax timing differences, OPG submitted that the regulation is clear and explicit. Further, OPG stated that the government was aware of the deferred tax liability through its review of OPG's business plan prior to the creation of the regulation.

OPG also observed that implementation of the regulation as a means to delineate a starting point was accepted by the Board in OPG's first proceeding in EB-2007-0905.

Board Findings

The Board's EB-2007-0905 decision dealt with tax issues that arose prior to regulation of OPG's prescribed assets. In that decision, the Board found that the benefit of tax deductions and losses that arose before the date of the Board's first order should be apportioned between electricity consumers and OPG based on the principle that the party who bears a cost should be entitled to any related tax savings or benefits.

The requirement set out in O. Reg. 53/05, section 6(2)11part ii, applicable to the newly regulated assets, is more descriptive than the requirement set out in 2008 when the Board issued its first rate order for OPG. The Board finds the regulations are sufficiently

[108] Reply Argument page 203

explicit; the values related to income tax effects of timing differences and the revenue requirement impact of accounting and tax policy decisions must be accepted by the Board.

As a result, the Board accepts OPG's proposed accounting treatment and cost consequences of the $181M in deferred income taxes associated with the newly regulated assets as it relates to income tax decisions reflected in the liabilities as of December 31, 2013. The Board notes that the requirements of O. Reg. 53/05 are unique to OPG. Deferred taxes are not ordinarily included in the revenue requirement and there is no impact to the current test period revenue requirement as a result of this finding.

5 BRUCE LEASE – REVENUES AND COSTS
(Issue 7.3)

OPG leases the Bruce A and Bruce B generating stations and associated lands and facilities to Bruce Power. Sections 6(2)9 and 6(2)10 of O. Reg. 53/05 provide that the Board shall ensure that OPG recovers all the costs it incurs with respect to the Bruce nuclear facilities, and that any revenues it earns from the Bruce Lease in excess of costs will be used to offset the nuclear payment amounts.

The EB-2007-0905 decision found that the Bruce nuclear facilities should not be treated as if they were regulated facilities. The current basis of accounting used for the Bruce nuclear facilities revenues and costs is USGAAP for non-rate regulated entities. Bruce revenues are derived from base and supplemental payments as set out in the Bruce Lease, used fuel storage and long term disposal services, low and intermediate waste management services, and support and maintenance services as set out in the Bruce Site Services Agreement. Costs include depreciation, which includes asset retirement costs, taxes, accretion, earnings/losses on nuclear segregated funds, the cost of used fuel storage and disposal, and the cost of waste management.

The Bruce Lease net revenues are forecast to be $39.7M in 2014 and $40.6M in 2015. If approved, these amounts would offset the nuclear revenue requirement. Variances are tracked in the Bruce Lease Net Revenues Variance Account.

SEC submitted that there is a $59M adjustment related to the adoption of USGAAP on January 1, 2011, that should not be permitted. SEC referred to interrogatory response Exh L-1.3-SEC-19 that showed OPG made a $59M one-time transitional adjustment on January 1, 2011 to comply with USGAAP lease accounting requirements. This treatment requires lease payments be recognized retrospectively on a straight line basis from the inception of a lease. SEC proposed that the $59M be credited to a deferral account. OPG argued that the adjustment was a required transition entry as part of the USGAAP opening balance sheet. OPG also argued that the SEC proposal would be inconsistent with Board direction that Bruce Lease net revenues be determined on a GAAP basis for non-regulated entities, and inconsistent with the settlement agreement in the USGAAP and Deferral and Variance Account proceeding, EB-2012-0002.

SEC submitted that it would be useful if the cost of generation from the Bruce nuclear facilities was provided to the Board on a regulatory basis in future cost of service proceedings for benchmarking purposes. OPG submitted that this proposal is inappropriate. The Board has already determined that Bruce nuclear facilities will not be treated as if they were regulated facilities. Further, OPG states that it is not privy to Bruce Power's cost of generation information.

Board Findings

The net amounts of the Bruce lease revenues and costs of $39.7M for 2014 and $40.6M for 2015 are approved.

OPG's adoption of USGAAP was reviewed in EB-2011-0432 and EB-2012-0002, and the Board agrees with OPG that the adjustment issue raised by SEC relating to USGAAP was dealt with as part of the settlement of the EB-2012-0002 proceeding. The Board also agrees that the previous cost of service decisions on Bruce Lease revenues and costs determined on the basis of GAPP for non-regulated entities are still appropriate.

The Board does not agree with the suggestion of SEC that OPG should file the cost of generation from the Bruce Generating Stations on a regulatory basis in future payment applications. The Bruce Generating Stations are neither regulated by this Board nor included as prescribed assets. The Board would not expect OPG to have information related to Bruce Power's costs and revenues.

6 NUCLEAR WASTE MANAGEMENT AND DECOMMISSIONING

(Issues 8.1 and 8.2)

OPG incurs liabilities for decommissioning its nuclear stations (including Bruce) and nuclear used fuel and low and intermediate level waste management.

The responsibility for funding these liabilities is described in the Ontario Nuclear Funds Agreement. This agreement requires OPG to establish two segregated funds:

- The used fuel fund
- The decommissioning fund – to fund the future cost of nuclear fixed asset removal, and low and intermediate level radioactive waste

In this proceeding OPG seeks recovery of $847.5M over the 2014 and 2015 test period for nuclear waste management and decommissioning for both prescribed nuclear and Bruce facilities*.*

The Ontario Nuclear Funds Agreement provides for the establishment of a reference plan for nuclear liabilities which must be updated every 5 years. The current approved Ontario Nuclear Funds Agreement reference plan became effective as of January 1, 2012. OPG's contributions to the used fuel fund and the decommissioning fund are determined based on the reference plan cost estimates.

The EB-2007-0905 decision approved a methodology for the recovery of nuclear liabilities that recognized a return on rate base associated with asset retirement costs for Pickering and Darlington. The methodology required that the return on the asset retirement cost be limited to the weighted average accretion rate, which is currently 5.37%. The portion of the rate base to which the accretion rate applies is equal to the lesser of (a) the forecast amount of the average unfunded nuclear liabilities related to the Pickering and Darlington facilities, and (b) the average unamortized asset retirement cost included in the fixed asset balances for Pickering and Darlington. In the previous two cost of service applications, and as proposed by OPG in the current application, (b) applies.

AMPCO observed that the decommissioning fund was overfunded by $624M at December 31, 2013, i.e. the value of the fund was higher than the balance required to meet all future obligations. The excess funding was shown as “Due to Province” in the audited financial statements.

The decommissioning fund has been overfunded in periods prior to Board regulation. AMPCO observed that in 2006, OPG recorded $190M from “Due to Province” credits to balance a $190M liability. AMPCO noted that the “Due to Province” cushion was used in 2006, 2007 and 2008.

During the oral component of this proceeding Board staff sought a calculation that reflected the application of the “Due to Province” amount to reduce unfunded nuclear liabilities, assuming a 53% allocation for the prescribed facilities. In completing the undertaking OPG stated that the “Due to Province” amount cannot be used in this manner. The resulting revenue requirement of the hypothetical scenario was higher than that proposed in OPG’s application as unfunded nuclear liabilities would be lower than the asset retirement costs. Under the Board-approved calculation methodology for nuclear liabilities cost recovery associated with the prescribed facilities, if the unfunded nuclear liability is lower than the unamortized asset retirement cost (ARC), cost recovery for the portion of the ARC amount is calculated using the higher weighted average cost of capital rate instead of the lower weighted average accretion rate.

AMPCO submitted that the calculations provided by OPG were misleading as the Bruce facilities were not considered. AMPCO revised the hypothetical calculations, allocating the $624M “Due to Province Amount” to the prescribed nuclear facilities and the Bruce facilities. AMPCO determined that the test period revenue requirement for nuclear liabilities should be reduced by $28.5M. OPG argued that it has properly reflected the requirements of the Ontario Nuclear Funds Agreement reference plan in the determination of nuclear liabilities and that AMPCO has failed to provide reasons why it disagrees with OPG’s interpretation. OPG’s treatment of the “Due to Province” amounts associated with the Bruce facilities is consistent with GAAP for non-regulated businesses.

AMPCO also observed that when the decommissioning fund is more than 120% overfunded, some of the excess can be transferred to the used fuel fund. AMPCO proposed a deferral account to record the amount the used fuel fund is entitled to. OPG argued that another account would require the Board to modify the scope of the existing Bruce Lease Net Revenues Variance Account.

AMPCO submitted that the Board should direct OPG to review its current nuclear liability methodology and any potential alternatives as part of the next payment amounts application.

Board Findings

The Board finds that the revenue requirement methodology approved by the Board in EB-2007-0905 continues to be appropriate for recovering nuclear liabilities. The Board does not find it necessary to direct a review of the current methodology at this time given the extensive Board review of the rate making options in EB-2007-0905.

The Board will not direct OPG to use the excess earnings in the Decommissioning and Used Fuel funds to decrease the revenue requirement by $28.5M as proposed by AMPCO as the funds are “Due to Province” as stipulated in the Ontario Nuclear Funds Agreement reference plan. The Board is satisfied that the current over funding position will not result in a cash withdrawal from the fund to the Province. In addition, given the long-term nature of the fund, it is appropriate for any periodic over earning to be retained within the fund to offset future potential under earning.

The Board will not approve the creation of a deferral account to record any excess earning in the decommissioning fund over 120%. Although any excess over 120% could be transferred to the used fuel fund, the Board does not find it necessary to create a regulatory asset when the reference plan is the source of record keeping and is updated every 5 years. The Board has no authority over the segregated funds or the reference plan for nuclear liabilities established by the Ontario Nuclear Funds Agreement.

The Board approves the recovery of $847.5M over the 2014 and 2015 test period for nuclear waste management and decommissioning for both prescribed nuclear and Bruce facilities.

7 CAPITAL STRUCTURE AND COST OF CAPITAL
(Issues 3.1 and 3.2)

7.1 Capital Structure

OPG did not apply for a change in capital structure in this proceeding. Rather, OPG proposed to use the same capital structure (53% debt and 47% equity) for all the regulated facilities, including the newly regulated hydroelectric facilities, which was originally approved in the first cost of service proceeding, EB-2007-0905, and again in the last cost of service proceeding, EB-2010-0008. In the current proceeding, OPG's proposed capital structure was supported by evidence (the "Foster report")[109] and expert testimony from Ms. Kathleen McShane of Foster Associates, Inc.

During the oral hearing, several parties challenged OPG's position that the capital structure was unchanged by the proposed $4 billion addition of the newly regulated hydroelectric facilities and Niagara Tunnel to rate base. These parties submitted that OPG's business risk has changed and that the equity thickness should be 42 to 43%.

SEC disagreed with Ms. McShane's view that the newly regulated hydroelectric facilities are more risky than the previously regulated hydroelectric facilities, but less risky than the nuclear facilities. SEC submitted that Ms. McShane has no independent knowledge of the business risks of the newly regulated hydroelectric facilities or the Niagara Tunnel, including First Nations issues, operating constraints or storage.

Noting that the Board concluded in EB-2007-0905 that the 47% equity thickness recommended by Drs. Kryzanowski and Roberts was appropriate, SEC submitted in the current proceeding that applying the methodology and parameters set out in Drs. Kryzanowski and Roberts' evidence in EB-2007-0905, namely 40% hydroelectric equity thickness and 50% nuclear equity thickness, to the proposed test period rate base would result in an overall equity thickness of 42.34%.

Board staff submitted that the Board did not approve the methodology of Drs. Kryzanowski and Roberts in EB-2007-0905, and that in the EB-2010-0008 proposal for technology specific cost of capital, Drs. Kryzanowski and Roberts revised the parameters to 43% hydroelectric equity thickness and 53% nuclear equity thickness.

[109] Exh L-3.1-SEC-24 Attachment 1

Should the Board accept the methodology and apply 43% equity thickness to all the hydroelectric facilities, Board staff submitted that the OPG equity thickness would be 45 to 46%.

OPG argued that none of the cost of capital experts that appear before the Board, including Drs. Kryzanowski and Roberts, have expertise in hydroelectric generation facilities. While the parties have challenged OPG's evidence and proposed reductions to equity thickness, none of the parties filed expert evidence to support their positions. OPG also argued that matters raised by some parties, e.g. comparisons with lower equity thickness for generators in other provinces by VECC, and the stand alone principle and 90% debt proposed by the Society, were previously addressed in EB-2007-0905. Further, as OPG is planning on spending more than $1.5 billion on the Darlington Refurbishment Project in the test period, OPG contends that its financial risk will increase in the test period.

Board Findings

In this application OPG did not request a change to its capital structure, claiming there had been no significant changes in the risks faced by its regulated asset portfolio that are not captured elsewhere in the application. While the application was filed in September 2013, no evidence was filed by OPG to substantiate this conclusion with respect to changes in risk until the interrogatory phase of the proceeding in March 2014.

The Foster report dealing with the capital structure and risk was not filed until March 19, 2014 in response to an interrogatory by SEC. The Board finds this late filing to be unfortunate, because the time between the report being publicly available and the date for intervenors to advise the Board of their intentions to file evidence was less than one week. The Board suspects that, had the Foster report been filed sooner, parties may have been in a better position to assess the merits of retaining their own expert on this matter. As it was, no alternative expert analysis was proffered and arguments by all parties were largely based on challenges to the Foster report.

The Board believes it would have been helpful to have had additional expert and independent evidence. The Board notes OPG's assessment that there had been no significant changes in risks was made before Foster Associates, Inc. was retained.[110] OPG appears to have made the initial assessment entirely on its own.

The Board cannot accept that business risk has not changed since the capital structure was last reviewed in 2010. Since that time, 48 additional hydroelectric facilities have been added to the inventory of prescribed assets, accounting for 12.4 TWh of energy forecast to be produced in 2014 and 12.5 TWh in 2015. These assets, together with the Niagara Tunnel which was brought into service in 2013, increase the proportionate share of rate base related to hydroelectric facilities from about half in 2010 to approximately two-thirds now. The relative business risk of hydroelectric generation versus nuclear has been accepted by the Board as being lower in previous proceedings,[111] even though setting the capital structure on a technology specific basis has not. The critical question therefore becomes whether business risk has changed in a significant enough way to warrant a change in capital structure, and in which direction is this change – lower or higher risk?

The Board finds that including additional hydroelectric units to the roster of prescribed assets lowers the business risk for several reasons. Subject to Board approval through this proceeding, these additional assets will be subject to treatment under a number of previously approved Board deferral and variance accounts for a host of variables, all of which reduce business risk. Since the equity component was first set, a new pension variance account has been approved by the Board. This variance account decreases OPG's forecast risk associated with pension and OPEB costs. The proportion of regulated assets between hydroelectric and nuclear generation has changed, with hydroelectric facilities now having a much larger share of the generating capacity of OPG than previously. It was acknowledged by OPG's consultant that hydroelectric facilities have lower risk than nuclear.[112] The new assets being added to rate base have long remaining service lives (average of 58 years for the newly prescribed assets[113]) and 95 years for the Niagara Tunnel. As long as there is rate regulation, these assets will produce power and revenue certainty until the end of their useful lives.

The Board considered the Foster report and makes the following observations.

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[110] Application is dated September 27th, 2013 while contract commencement date is September 30th, 2013. (Undertaking J10.2)
[111] Decision with Reasons, EB-2010-0008, page 116
[112] Tr Vol 10 page 30
[113] Undertaking J12.3

- No independent analysis was undertaken of the operating costs and lives of the newly prescribed assets. The consultant's opinion was based on discussions with OPG staff only. While information obtained from operating personnel is an important component to assessing risk, the lack of independent knowledge of the circumstances of OPG's newly regulated hydroelectric operations is a concern.
- The opinion that the newly regulated assets have increased risk due to their location in Northern Ontario within First Nations communities and their traditional ways of life was not substantiated by fact. It appears this was conjecture on the part of the consultant based on conversations with OPG management.
- There was no evidence as to the impact of a change in equity thickness on the credit metrics.

OPG raised various other arguments with respect to the need for at least the same, or higher, equity thickness. One of these arguments was that there is a greater risk associated with the future move to incentive regulation. The Board does not accept that moving to incentive regulation significantly increases risk to the entity such that the capital structure should be reset, and has not done so for any of the other companies that it regulates. For example, the Board set the capital structure for all electricity distributors at a 40% equity to debt ratio in December 2006. As new incentive regulation models for electricity distributors evolved in 2008[114] and 2012[115], this capital structure was not revisited. Similarly, the capital structure for the natural gas distributors did not change as a result of moving to a long-term incentive regulatory mechanism for the setting of rates for these distributors. In addition, OPG is not actually being moved to incentive regulation in the current proceeding, and any potential changes to business risk this may entail could be considered in the incentive regulation proceeding. The Board therefore is not persuaded by the comments made by OPG and its consultant that the future move to an incentive regulatory mechanism for OPG increases business risk such that a higher equity thickness should be considered.

Instead, the Board has determined that business risk has changed for this payment setting period, and that the business risk is reduced. The business risk is reduced because of the addition of significant hydroelectric assets to rate base, which are less risky than nuclear assets.[116] The Board finds that a more appropriate equity thickness

[114] Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors, July 14, 2008
[115] Report of the Board Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach, October 18, 2012
[116] Exh L-3.1-SEC-24, Attachment 1 page 23, Tr Vol 10 page 30

is 45%. This equity thickness is still considerably higher than any other entity regulated by the Board.

The Board does not accept the Society's argument that due to the change in the energy environment that the well accepted principles of a stand-alone entity should be abandoned and also that OPG can have up to a 90% debt operating structure due to its ownership structure. The Board has previously commented on the validity of the stand-alone principle and as neither of these issues was explored in sufficient detail through cross-examination or the production of independent expert evidence, the Board sees no justification for such a major change.[117]

In reaching this conclusion the Board was mindful of the Fair Return Standard as articulated by the courts, and the need to observe the requirements of consideration of comparable investment, financial integrity and capital attraction. However, the Fair Return Standard is sufficiently broad to allow a regulator to apply informed judgment and discretion in the determination of a rate regulated entity's cost of capital. The Board believes that a reduction to equity thickness is based on the evidence in this case, the Board's best judgment and is a reasonable outcome.

As a result of its review, the Board finds that the capital structure should be based on 45% equity and 55% debt.

7.2 Return on Equity

OPG's current proposal is to apply 9.36%, the Board's ROE for 2014 cost of service applications, for 2014 and 9.53% for 2015 based on Global Insights data from September 2013.

In the event that the Board's ROE for 2015 cost of service applications was available at the time of the payment order, Board staff submitted that the Board's ROE, based on more recent *Consensus Forecasts*, be used instead of the 9.53% proposed by OPG based on Global Insights data from September 2013.

OPG replied that Board staff's proposal would involve data after the close of record and would be a departure from the methodology used for setting the ROE in the second

[117] Decision with Reasons, EB-2007-0905, pages 137–142

year of the test period as adopted by the Board in the previous payment amounts decisions.

In addition to proposing a 90% debt structure, the Society submitted that the allowed return should be the social discount rate. OPG argued that the social discount rate was not addressed in this proceeding.

Return on Equity for Newly Regulated Hydroelectric Facilities

In the current application, OPG proposes to add $2.5 billion to rate base in relation to the newly regulated hydroelectric facilities.

Environmental Defence did not object to the addition, referring to the requirements of O. Reg. 53/05, however, Environmental Defence submitted that 50 to 60% of the addition is related to the revaluation of assets process that occurred when OPG was created as one of the successors to Ontario Hydro. Environmental Defence submitted that this portion of OPG's rate base should not earn the ROE, but instead should attract a return based on long-term debt. Environmental Defence also submitted that the Board should consider this treatment for the previously regulated hydroelectric facilities in the next proceeding.

OPG argued that "a package of assets" was sold to OPG in exchange for certain debt and equity amounts as part of the restructuring process. This was done to make OPG a viable operation on a stand-alone basis. Further, Environmental Defence's submission is inconsistent with the Board's treatment of the previously regulated hydroelectric facilities in the first proceeding.

CME submitted that the Board should consider the cost of capital supporting the newly regulated hydroelectric assets at December 31, 2013. The newly regulated hydroelectric facilities, on a stand-alone basis at December 31, 2013, were producing an actual loss from operations. In CME's view, the cost of capital supporting the newly regulated hydroelectric assets should be the interest rate that applies to "stranded debt" which CME estimates to be 5.9%.

OPG argued that the newly regulated hydroelectric facilities, prior to becoming regulated, were being financed by the debt and equity of the consolidated OPG. The fact that the newly regulated hydroelectric facilities were not earning their cost of capital on December 31, 2013 does not mean that their cost of capital was equal to the cost of debt. Further, OPG's 2013 audited financial statements do not contain an impairment charge for these assets.

Board Findings

With respect to Return on Equity, the Board's Return on Equity for 2014, 9.36% will apply for the 2014 test year. As the Board's 2015 cost of capital parameters will be available when the payment order process for the current proceeding is underway, the Board's Return on Equity for 2015 will apply for the 2015 test year.

The Board notes that the revaluation of the newly regulated assets was undertaken at the time of Ontario Hydro restructuring about 15 years ago. As a result of this restructuring, Environmental Defence proposes to have the newly regulated assets earn a return based on long-term debt. The Board finds this inappropriate and inconsistent with prior Board Decisions, e.g., EB-2007-0905 when the previously regulated hydroelectric facilities were first regulated by the Board.

The Board has reviewed CME's submission and has determined that the Return on Equity determined above will apply to all regulated assets.

7.3 Short Term Debt and Long Term Debt

OPG proposes, for Board approval, the following debt rates for the test period.

	2014	2015
Long-term Debt	4.85%	4.86%
Short-term Debt	1.87%	2.89%

There were no opposing submissions filed.

The Board accepts that the long-term and short-term debt rates proposed by OPG are appropriate. The final approved debt costs will be adjusted by the rate base and capital structure findings found elsewhere in this Decision.

8 DEFERRAL AND VARIANCE ACCOUNTS

There are currently 15 deferral and variance accounts for OPG that were established pursuant to O. Reg. 53/05 or Board decisions.

In the EB-2012-0002 USGAAP and Deferral and Variance Account proceeding, the Board accepted the settlement proposal of the parties. The audited balances as of December 31, 2012 in the deferral and variance accounts were approved for disposition, except for four accounts. The EB-2012-0002 proceeding established payment riders for 2013 and 2014. The 2014 riders are $2.02/MWh for the previously regulated hydroelectric facilities and $4.18/MWh for the nuclear facilities.

8.1 Clearance of Accounts in the Current Proceeding

(Issues 9.1, 9.2, 9.3 and 9.4)

In the current proceeding, OPG seeks clearance of the 2013 year end balances for the following four accounts in riders starting January 1, 2015.

- Hydroelectric Incentive Mechanism Variance Account
- Hydroelectric Surplus Baseload Generation Variance Account
- Capacity Refurbishment Variance Account – Hydroelectric and Nuclear (OPG is not seeking clearance of the nuclear non-capital cost account additions)
- Nuclear Development Variance Account

The audited 2013 year-end balances for the hydroelectric accounts listed above is $126.9M, however, OPG proposes to clear the capacity refurbishment variance hydroelectric sub-account over 2 years. The 2015 hydroelectric amortization amount proposed is $70.6M. The audited 2013 year-end balance for the nuclear accounts listed above is $62.2M.

Board staff and LPMA had no concerns with the balances in the four accounts for which OPG seeks disposition in this proceeding. LPMA submitted that the recovery period could be extended if mitigation is required. Board staff submitted that the right to re-examine the accounts that are not being disposed in this proceeding should be reserved for the future application that will dispose of them. In reply, OPG accepted that these accounts should be re-examined when the balances are disposed.

SEC submitted that there is no basis on which to approve the addition of several Darlington Refurbishment campus plan projects to rate base, e.g. the Darlington Operations Support Building refurbishment. SEC submitted it would be reasonable to add this to the Capacity Refurbishment Variance Account, so that when proper evidence is filed in a future proceeding, it can be added to rate base at that time. OPG argued that there is no basis to SEC's objections and no reason to conclude that the balance in the capacity refurbishment account is incorrect.

The 2013 year-end balance in surplus baseload generation account is $19.2M. The 2011-2013 unintended benefit to OPG of the interaction between surplus baseload generation and the hydroelectric incentive mechanism has been determined to be $6.8M in undertaking J4.7. Both CME and VECC submitted that the $6.8M should be returned to ratepayers. OPG argued that the proposed adjustment is improper because it amounts to retroactive ratemaking. The Board's EB-2010-0008 decision established the terms for account entries and no party argued that the balances in the accounts were not accurately calculated.

Board Findings

The Board approves disposition of the audited December 31, 2013 balances in the four variance accounts. The Board does not find it necessary to mitigate the rate impact for the Capacity Refurbishment Variance Account hydroelectric sub-account with a 2 year amortization period as the account balance is $112.7M. As proposed by OPG, the riders shall commence on January 1, 2015. The riders will end on December 31, 2015.

The Board will not adjust the balance in the Hydroelectric Surplus Baseload Generation Variance Account to eliminate the unintended benefit realized by OPG, as proposed by CME and VECC. The Board does not find it appropriate to alter the terms and calculation approved in EB-2010-0008 to accommodate new information that was not available at the time of the Board's decision. Changing the December 31, 2013 account balance would not be retroactive ratemaking, as any variance account balance is subject to change prior to final disposition by the Board. However, the proposed adjustment would be improper as this was not addressed in the Board's EB-2010-0008 decision.

In addition, the Board will not require OPG to make additional entries to the Capacity Refurbishment Variance Account. The Board has approved the rate base additions related to the Darlington Refurbishment campus plan projects as proposed by OPG, and therefore, there is no residual unapproved balance to transfer to the variance account as proposed by SEC.

8.2 Continuation of Accounts and New Accounts (Issues 9.5, 9.7, 9.8. 9.9)

OPG requested the continuation of the following accounts:

- Hydroelectric Water Conditions Variance Account
- Ancillary Services Net Revenue Variance Account – Hydroelectric and Nuclear Sub-Accounts
- Hydroelectric Incentive Mechanism Variance Account
- Hydroelectric Surplus Baseload Generation Variance Account
- Income and Other Taxes Variance Account
- Tax Loss Variance Account
- Capacity Refurbishment Variance Account
- Pension and OPEB Cost Variance Account
- Impact for USGAAP Deferral Account
- Hydroelectric Deferral and Variance Over/Under Recovery Variance Account
- Nuclear Liability Deferral Account
- Nuclear Development Variance Account
- Bruce Lease Net Revenues Variance Account – Derivative and Non-Derivative Sub-Accounts
- Pickering Life Extension Depreciation Variance Account
- Nuclear Deferral and Variance Over/Under Recovery Variance Account

The total year end 2013 debit balance for all accounts is $217.3M for the previously regulated hydroelectric facilities and $1,478.4M for the nuclear facilities. OPG plans to seek clearance of the December 31, 2014 balances in all its deferral and variance accounts through a separate application to be filed in 2014.

As set out in EB-2012-0002, OPG will terminate the Tax Loss Variance Account and the Impact for USGAAP Deferral Account on December 31, 2014, with any remaining balance transferred to the over/under variance accounts. OPG has proposed an enhanced hydroelectric incentive mechanism in the current proceeding that eliminates the need for future additions to the Hydroelectric Incentive Mechanism Variance Account.

OPG has proposed to extend the application of four variance accounts specific to hydroelectric operations and three common cost variance accounts (i.e., accounts that impact both hydroelectric and nuclear operations) to its newly regulated hydroelectric operations. The newly regulated hydroelectric accounts would be subaccounts of existing accounts. Entries to the accounts would commence on the effective date of the payment amounts.

In the EB-2012-0002 settlement proposal, accepted by the Board, no interest was to be applied to the balance in the Pension and OPEB Cost Variance Account for the 2 year period ending December 31, 2014. OPG proposes that interest will resume on January 1, 2015. Board staff submitted that the variances in the Pension and OPEB Cost Variance Account have been actuarially determined and that interest should not apply to be consistent with other decisions of the Board. OPG did not reply on this matter.

No parties objected to OPG's proposal to extend existing accounts to include the newly regulated hydroelectric facilities.

Board staff and other parties have supported the continuation of the current hydroelectric incentive mechanism, and keeping the hydroelectric incentive mechanism variance account open to additions. Board staff and other parties also submitted that the Hydroelectric Incentive Mechanism Variance Account should also apply to the incentive mechanism revenue related to the newly regulated hydroelectric facilities. OPG agreed that it would be appropriate to continue additions to the account if the Board decides to retain the current hydroelectric incentive mechanism. However, the current variance account is asymmetrical. If OPG fails to earn its half of the incentive net revenues, it owns the loss, whereas ratepayers are fully protected. OPG submitted that the account should act both ways.

If the Board approves a cash basis for pension and OPEB, Board staff submitted that it would be reasonable for the Board to approve a variance account for differences in forecast cash payments included in revenue requirement and actual cash payments. It would also be reasonable that carrying charges would apply to the cash variance. OPG has serious concerns with respect to cash basis determination for pension and OPEB. However, if the Board proceeds with this methodology, the account would be required.

Board staff submitted that Ministry of Natural Resources approval of a 10 year gross revenue charge holiday for the Niagara Tunnel Project is highly likely, however, that holiday is not reflected in the current application. Board staff submitted that an account should be set up to capture the gross revenue charge costs for return to ratepayers. OPG had no objection to this submission.

In its submission on nuclear liabilities, AMPCO proposed a deferral account to record 50% of an excess of 120% of the decommissioning fund balance. SEC submitted that there is a $59M adjustment related to the Bruce Lease and the adoption of USGAAP on January 1, 2011, that should not be permitted. SEC proposed that the $59M be credited to a deferral account. OPG does not support either of these accounts, arguing that there is no basis for making the adjustments.

Board Findings

The Board approves the continuation of existing deferral and variance accounts as proposed by OPG, with two exceptions.

First, the Board directs OPG to maintain the Hydroelectric Incentive Mechanism Variance Account as the Board has rejected the alternative enhanced hydroelectric incentive mechanism proposal. OPG will maintain the current mechanism with the one variation that eliminates the unintended benefit to OPG. As a result, the variance account will also be maintained to track any revenues earned over the incentive thresholds of $78M in 2014 and $96M in 2015. The Board will maintain the account's asymmetrical structure and purpose, and extend the account's application to include the newly regulated hydroelectric assets.

Second, the Board rejects OPG's proposal to accrue interest on the balance in the Pension and OPEB Variance Account after December 31, 2014. The Board finds no compelling reason to change OPG's current practice of maintaining the balance without interest, which was part of the EB-2012-0002 settlement proposal approved by the Board.

Regarding the creation of new accounts, the Board accepts OPG's proposal to extend seven variance accounts to the newly regulated hydroelectric assets. The Board has included an eighth account, the Hydroelectric Incentive Mechanism Variance Account as previously approved. New sub accounts will need to be created for the newly regulated assets, extending the applicability of the existing variance accounts. Entries to the accounts will commence on the effective date of the payment amounts for the newly regulated hydroelectric facilities.

In addition, the Board approves the creation of a variance account to track any variance in the gross revenue charge forecast to be paid for the Niagara Tunnel Project. A charge is forecast and included in the 2014 and 2015 payment amounts, yet the approval is outstanding for a 10-year gross revenue charge exemption for the Niagara Tunnel Project. The new account will be called the Gross Revenue Charge Variance Account.

As noted in the Pension and OPEB Accounting section of this Decision, the Board approves a new variance account to track any contributions that differ from the minimum cash requirements, as included in the 2014 and 2015 payment amounts. Interest will apply to this variance account given that it relates to cash payments. This new account will be called the Pension & OPEB Cash Payment Variance Account.

In addition, the Board has approved the establishment of a new deferral account to track the differential between the accrued and cash valuations for pensions and OPEBs. The Board does not approve the accrual of interest on the deferral account balance given that it tracks non-cash items. The new account will be called the Pension & OPEB Cash Versus Accrual Differential Deferral Account.

As proposed by OPG, the Tax Loss Variance Account and the Impact for USGAAP Deferral Account will be terminated effective December 31, 2014.

8.3 Future Disposition of Accounts

(Issue 9.6)

As noted previously, OPG plans to seek clearance of the December 31, 2014 balances in all its deferral and variance accounts through a separate application to be filed in 2014.

Board staff observed that the current proceeding is the third proceeding in which OPG has filed for clearance of deferral and variance accounts on the basis of forecasts with audited account balances filed later in the proceeding. No other utilities do this and this type of filing creates inefficiency as initial assessments are repeated when the audited balances are filed. Board staff suggested that the Board may wish to consider whether it will permit OPG to continue to file on the basis of estimates. Board staff also submitted that OPG did not provide sufficient rationale with its application, as filed on September 27, 2013, to limit clearance to only four deferral and variance accounts. The Board may wish to consider that the most effective and efficient means of assessing deferral and variance account balances is to do so at the time of also assessing a utility's costs of service, given the links between certain of the accounts and the revenue requirement.

OPG replied that the efficiency impact of filing deferral and variance account balances on a forecast basis is insignificant. Limiting account clearance to 4 accounts was sensible and appropriate given the size, duration and complexity of the current application. OPG stated that its approach made the current case more manageable.

LPMA submitted that the Board could consider denying additional carrying costs for the accounts OPG has proposed not to clear in this proceeding. OPG replied that this matter was not put to an OPG witness. The submission is punitive and should be rejected.

Board Findings

The Board does not endorse OPG's decision to bifurcate its cost of service issues into two separate proceedings, deferring its application for disposition of deferral and variance accounts to a later date. The Board accepted OPG's separate application in the EB-2012-0002 proceeding application but the Board did not intend to endorse a new, unique rate-setting approach for OPG. It is not a common practice of any other entity regulated by the Board to apply for a separate proceeding to dispose of deferral and variance accounts, other than when the entity is under a long-term incentive regulation method for rate-setting. This is not the case for OPG at this time. The Board does not accept OPG's statement that it proposed this two-step approach in order to manage and expedite the review of other issues in the application. With all of the complex issues included in this application, adding the clearance of deferral and variance accounts would not have added significant time or burden to this proceeding.

As a result of OPG deferring its application for disposition of deferral and variance accounts, the Board is unable to render a decision on the need for rate mitigation in 2014 and 2015, based on the overall bill impact resulting from OPG's operations. This creates a difficult situation for ratepayers who will not understand the full impact on payment amounts for 2014 and 2015 until the second application is completed. Based on the evidence filed, the account balances to be cleared in a second application will be significant.

While the Board has approved OPG's proposal to limit the clearance of deferral and variance accounts in this proceeding to the four accounts put forth by OPG, it is the Board's expectation that going forward, all accounts should be reviewed and disposed of in a cost of service proceeding unless there is a compelling reason to not do so. The Board agrees with Board staff that the optimal time to review all accounts is at the time of a cost of service review, based on the most recently audited account balances rather than forecasts. Any mitigation measures that may be required can also be considered at that time. This approach is consistent with the treatment of deferral and variance accounts for electricity distributors.

9 REPORTING AND RECORD KEEPING REQUIREMENTS (Issue 10.1)

Board staff observed that OPG has in several instances made changes to regulatory accounting during the period outside of its payment applications. The changes affect the accounting basis on which the rates were approved. As an example, Board staff noted that OPG extended the useful life of Pickering effective December 31, 2012, resulting in a decrease in depreciation of $47M annually.

Board staff submitted that OPG should be directed to first seek Board approval through an accounting order that outlines the nature of the change and the impact. Board staff suggested that a revenue requirement threshold of $20M be used, for accounting changes, whether arising from a single or multiple transactions, and noted that the EB-2012-0002 has a similar provision for nuclear liability accounting changes that have a revenue requirement impact of $10M or more annually. SEC did not agree with a threshold as any change could be applicable for three years before rates are changed.

OPG submitted that a requirement to seek Board approval for accounting changes would be a burden for both OPG and the Board. However, OPG concluded that the Board staff submission is really focused on accounting changes that impact depreciation expense and the related impact on accumulated depreciation and rate base. OPG replied that it would support the expansion of the nuclear liability requirement set out in EB-2012-0002 to include impacts of changes in station useful lives on non-asset retirement cost component of nuclear fixed assets reflected in rate base. This requirement would capture future changes similar to the $47M Pickering depreciation expense example.

If the Board is inclined to require accounting orders for a broader range of accounting matters, OPG submitted that a $20M threshold would be more appropriate to keep the requirement manageable.

Board Findings

The Board will not require OPG to seek prior Board approval of all accounting changes made between payment amount applications. The Board finds accounting decisions should continue to be made by OPG's management. The Board's responsibility is to approve the future recovery of expenses through the determination of OPG's payment amounts, based on the evidence available. At that time, the Board will opine on the proposed, underlying accounting treatment by OPG.

Upon application for new payment amounts and where an accounting change has occurred, OPG must include historical information that enables the comparison between years of expenses and impact on elements which form part of the payment calculation. This will involve the preparation of continuity schedules showing the impact of the accounting change such that year over year comparisons are transparent and readily apparent. The Board notes that this is not a new requirement, as the OPG filing guidelines (EB-2011-0286) already stipulate that changes in accounting methodologies that affect any of the historic, bridge or test years must be provided.

OPG also has nuclear liabilities reporting requirements as set out in EB-2012-0002.

> OPG shall file an accounting order application with the Board and provide notice to intervenors of record in EB-2012-0002 if, other than as a result of an Ontario Nuclear Funds Agreement Reference Plan update, OPG proposes to effect an accounting change impacting the calculation of its Nuclear Liabilities that results in a revenue requirement impact for the prescribed facilities that is neither reflected in the current or proposed payment amounts nor recorded in the Nuclear Liability Deferral Account (including, without limitation, any change in the useful lives of any asset for depreciation or amortization purposes). OPG shall not be required to apply for such accounting orders if the impact on the annualized revenue requirement impact for the prescribed facilities is less than $10M.[118]

In this proceeding, OPG has agreed to expand these requirements to include impacts of changes in station useful lives on the non-asset retirement cost component of nuclear fixed assets reflected in rate base. As a result, the Board approves this extension of the nuclear reporting requirements and requires OPG to provide notice to any additional intervenors of record in this proceeding, EB-2013-0321.

[118] Payment Amounts Order, EB-2012-0002, April 13, 2013

10 METHODOLOGIES FOR SETTING PAYMENT AMOUNTS

10.1 Incentive Regulation

(Issue 11.1)

O. Reg. 53/05 empowers the Board to establish the “form, methodology, assumptions and calculations” to be used in setting payment amounts for OPG’s prescribed generation assets. While the current proceeding is the third cost of service proceeding, the Board has indicated its intention to “implement an incentive regulation formula for OPG when it is satisfied that the base payment provides a robust starting point for that formula.”[119] The Board has communicated its intention in the report, *A Regulatory Methodology for Setting Payment Amounts for the Prescribed Generation Assets of Ontario Power Generation Inc.*, EB-2006-0064, issued on November 30, 2006, the EB-2010-0008 Decision with Reasons issued on March 10, 2011 and most recently, the *Report of the Board on Incentive Rate-making for Ontario Power Generation’s Prescribed Generation Asset*, EB-2012-0340, issued on March 28, 2013.

On the basis of a consultative process, the EB-2012-0340 report set out a timeline to establish incentive regulation for the hydroelectric business and multi-year cost of service for the nuclear business assuming a 2014-2015 cost of service application filing in mid-2013. As the current application was not filed until September 2013 and a decision is not expected until late 2014, Board staff has submitted that working groups would not be initiated until early 2015, at the earliest. It would be many months before a Board report based on the working group’s analysis and recommendations could be issued. Board staff submitted that it is unlikely that incentive regulation will be implemented prior to the filing of an application for 2016 payment amounts.

In reply, OPG suggested that the working groups could be initiated in November 2014. OPG has contracted with London Economics Inc. to conduct the independent hydroelectric study requested by the Board in EB-2010-0008. OPG proposed that the working groups could review that study, and that the study and any working group materials could be made public once the decision in the current proceeding was issued.

[119] Board Report – A Regulatory Methodology for Setting Payment Amounts for the Prescribed Generation Assets of Ontario Power Generation Inc., EB-2006-0064, November 30, 2006

Notwithstanding the Board's position, CCC has submitted that OPG may not be the type of entity that can be regulated through an incentive regulation model. CCC submitted that the working groups should consider whether incentive regulation is appropriate for OPG as a threshold issue.

LPMA submitted that incentive regulation for the hydroelectric facilities may be premature as there is no history related to the newly regulated hydroelectric facilities under regulation. The Society submitted that "incentive rates are an implicit acknowledgement of a lack of expertise."[120]

Board Findings

The Board has indicated in previous decisions its objective of having OPG payment amounts set on an incentive regulation methodology ("IRM"). The Board continues to believe that a long-term, properly designed IRM has the potential to lead to operational efficiencies and innovation, and thus lower electricity costs. Progress in this direction of an IRM to payment setting has been made, with the issuance of the Board's Report on *Incentive Regulation for Ontario Power Generation's Prescribed Assets* (EB-2012-0340).

OPG shall file the London Economics Inc. study immediately upon completion. Recommendations on the details of the IRM are to be established through a working group, comprised of OPG, Board staff and stakeholders. The Board sees no reason for delay. The Board remains committed to setting payment amounts for the nuclear assets under IRM as well. However, the Board will wait until the Darlington Refurbishment Project is further advanced before issuing further direction in this regard.

10.2 Payment Design and Mitigation

(Issue 11.2 and 11.3)

OPG has determined that the payment amount increase sought in the current application, including the newly regulated hydroelectric facilities, is 23.4%. The estimated bill impact is an increase of $5.31 per month on the bill of a typical residential consumer. As the bill impact is less than 10%, OPG has not proposed any mitigation.

[120] Society Submission page 11

Board staff noted that the 23.4% increase in payment amounts is the largest increase OPG has proposed in a cost of service application. In addition, OPG will be seeking to dispose of further significant balances by way of a stand-alone deferral and variance account application shortly following this proceeding. Board staff submitted that some consideration of mitigation was appropriate.

The newly regulated hydroelectric facilities currently receive payment for generation based entirely on the Hourly Ontario Energy Price ("HOEP"). OPG seeks a payment amount of $47.57/MWh, which is a 59% increase over the $30/MWh proxy for HOEP that OPG has assumed for this application. Board staff submitted that the Board could consider approving half of the increase for the 2014 test year, and the full increase for the 2015 test year. These 2014 payment amounts would be higher than the 2009-2013 historical HOEP. SEC disagreed with the Board staff proposal. SEC submitted that the intent of O. Reg. 53/05 is that the newly regulated hydroelectric facilities will move to a "normal" regulated rate effective July 1, 2014.

OPG argued that the Board staff proposal without a deferral account is really the confiscation of prudently incurred costs that OPG is legally entitled to recover. The proposal is contrary to expert reports filed in other Board proceedings that refer to phase-in of rates and deferred amounts recognized as regulatory assets, and implementation such that there is no harm to the utility.

Board Findings

The design of the regulated hydroelectric and nuclear payment amounts is the same as had been established through the previous two payment amount proceedings, and no changes have been proposed. The Board accepts the existing payment amounts design for 2014 and 2015.

No mitigation of payment amount increases is approved in this Decision. It should be noted that the total bill impact to ratepayers over the test period will be dependent upon another application and proceeding related to disposition of OPG's deferral and variance account balances as at December 31, 2014, and which will likely seek rate riders starting in 2015 to account for the clearance of these deferral and variance accounts. The need for mitigation should be an issue in this subsequent proceeding, in the context of OPG's total bill impact.

11 IMPLEMENTATION

(Issue 12.1)

OPG requests an effective date of January 1, 2014 in respect of the previously regulated hydroelectric and nuclear facilities, and an effective date of July 1, 2014 for the newly regulated hydroelectric facilities. With respect to the newly regulated hydroelectric facilities, section 6(2)11 of O. Reg. 53/05 states the following:

> In making its first order under section 78.1 of the Act in respect of Ontario Power Generation Inc. that is effective on or after July 1, 2014, the following rules apply:
>
> i. The order shall provide for the payment of amounts with respect to output that is generated at a generation facility referred to in paragraph 6 of section 2 during the period from July 1, 2014 to the day before the effective date of the order.

At OPG's request, the Board issued an interim payment amounts order on December 17, 2013, declaring the payment amounts for the previously regulated hydroelectric and nuclear facilities interim as of January 1, 2014, and the newly regulated hydroelectric facilities as of July 1, 2014.

OPG argues that: "having declared current payment amounts interim as of the dates set out above, the OEB is obliged to make the payment amounts it determines to be just and reasonable after a review of the application effective from those dates. The time taken to process and review OPG's application is legally irrelevant."[121] In its Argument-in-Chief, OPG relied on *Bell Canada v. Canada (Canadian Radio-Television and Telecommunications Commission)*, [1989] 1 S.C.R. 1722 ("Bell"). The Bell decision establishes that the Board has the power to retrospectively set the implementation date of the decision back to the date that payment amounts were declared interim. OPG argues that this power, when coupled with the requirement that the Board must ensure that at all times payment amounts are just and reasonable, amounts to a legal requirement that the Board set the effective date of the order back to the date payment amounts were declared interim.

With respect to the newly regulated hydroelectric facilities, CME submitted that section 6(2)11 of O. Reg. 53/05 cannot override the Board's powers to set just and reasonable

[121] Argument-in-Chief, page 146.

rates. The overall impact on consumers of OPG's proposals needs to be considered in the context of the retroactivity component of the relief OPG seeks. CME submitted that none of the retroactive amounts should be recoverable from ratepayers. OPG disagreed with CME's submission observing that there is no conflict between the Act and the regulation as the Act provides for combined operation of section 78.1(2) and the regulation.

Board staff argued that the Bell case gives the Board the ability to retrospectively adjust final rate orders back to the date the interim order was issued, but it does not require the Board to do so.

Several other parties disagreed with OPG and proposed a range of different effective dates for the respective payment orders. SEC and CCC argued that the timing of the filing of the application was entirely within OPG's control. SEC pointed to the extensive updates that were filed by OPG throughout the proceeding, which resulted in additional delay. These parties submitted the effective date for the previously regulated assets should be the month following the date of the payment order. Board staff submitted that July 1, 2014 should be the effective date for all payment amounts as it was the earliest possible date a decision and payment order could have been completed based on a September 27, 2013 filing.

Board Findings

The Law Respecting Interim Orders

The Board does not accept that there is a legal requirement that it set the effective date of its final orders to the date that rates were declared interim. OPG's view is not supported by the wording of the legislation, the case law, nor the Board's practice.

The Board's power to set interim rates derives from section 21(7) of the Act: "[t]he Board may make interim orders pending the final disposition of a matter before it." As the use of the word "may" reveals, there is no requirement that the Board issue interim rate orders at all. As the decision to issue an interim order is discretionary, it follows that any decision to draw the effective date of the final payments order back to the date of the interim order is also discretionary. Nothing in the legislation suggests that the issuance of an interim order in any way ties the Board's hands with respect to the effective date of the final order. If the Legislature had intended that the Board be required to match the effective date of an order to the date interim rates were declared, it would have written that into the legislation. This was not done, and the Legislature has instead left the matter to the Board's discretion.

The Bell decision referred to by OPG establishes that interim rate orders give the Board the *ability* to retrospectively alter rates (or in this case payment amounts) back to the date the interim order was issued. As the Board stated in its decision in EB-2005-0361, nowhere does Bell state, or even suggest, that the Board is *required* to do so. Instead, the language of Bell suggests a permissive or discretionary approach. The Court stated: "It is inherent in the nature of interim orders that their effect as well as any discrepancy between the interim order and the final order <u>may</u> be reviewed and remedied by the final order."[122] The Bell decision does not support OPG's conclusion that the Board is legally required to align the effective date to the interim date, and OPG has not pointed to any other cases which support its position.

The Board issued the interim payment amounts order on December 17, 2013 at OPG's request and without any input from any other party. The Board was clear that by declaring rates interim it was not committing itself to ultimately setting the effective date of the final order to match the interim date: "This determination [i.e. the order declaring payment amounts interim] is made without prejudice to the Board's ultimate decision on OPG's application, and should not be construed as predictive, in any way whatsoever, of the Board's final determination with regards to the effective date for OPG's payment amounts arising from this application."[123]

Although OPG questioned in final argument whether the Board even has the ability to set an effective date to some date other than the interim date, it made no comment on this point when it made its request for interim payment amounts, nor when the interim order was issued. Given that the sentence quoted above is commonly included in the Board's interim orders, the Board is surprised to hear for the first time in OPG's final argument that OPG feels the Board lacks this authority. The very reason that the Board generally issues interim orders without seeking submissions from parties is that parties will be given the opportunity to ask questions and make submissions about the effective date of the final order throughout the hearing process. If the Board is legally required to match the effective date to the interim date, as OPG argues, then the issuance of the interim order without process arguably represents a breach of the "right to be heard"

[122] Bell, page 1752 (emphasis added)
[123] Interim Payment Amounts Order, December 17, 2013

principle. In the current case, ratepayer groups would be responsible for hundreds of millions of dollars in costs relating to the “interim” period without being afforded any opportunity for comment at all.

OPG argues that the Board has an obligation to ensure that rates are just and reasonable at all times. As a general statement, this is true. However, the Board’s power to consider and set what makes a just and reasonable rate is very broad and allows significant flexibility. The obligation to ensure that rates are always just and reasonable does not mean that the Board must examine and adjust a utility’s rates on a constant basis. Most utility’s rates are set on a forecast basis, for example, and invariably these forecasts turn out to be inaccurate to some extent. Absent extraordinary circumstances, the Board does not intervene to adjust rates simply because actual costs or revenues are different from what was forecast – even though the Board has the power to do so. In other words, there is a measure of “wiggle room” in a just and reasonable rate. Just and reasonable rates can fall within a range, and there is no defined line past which rates immediately become “unreasonable”. Indeed, under incentive regulation rates are deliberately de-coupled from a utility’s actual costs. The Board therefore does not agree with OPG’s argument that the requirement to ensure just and reasonable rates at all times leads to an automatic requirement to match the effective date with the date interim rates were set.

Effective date for the Nuclear and Previously Regulated Hydroelectric Payment Amounts

The Board has determined that the effective date for the payment amounts for the nuclear and previously regulated hydroelectric facilities will be November 1, 2014. The Board is not prepared to accept the January 1, 2014 effective date proposed by OPG as it is contrary to the Board’s long-standing practice of setting rates on a forecast (i.e. forward test year) basis.

The Board’s general practice with respect to the effective date of its orders is that the final rate becomes effective at the conclusion of the proceeding. This practice is predicated on a forecast test year which establishes rates going forward, not retrospectively. Going forward, the utility knows how much money it has available to spend and the ratepayer knows how much it is going to cost to use electricity in order to make consumption decisions. The forecast test year enables both the utility and the ratepayer to make informed decisions based on approved rates. The forecast test year is a pillar in rate setting and the Board's practice must be respected.

The Board must control its regulatory process. The Board hears a large number of cases throughout the year and must plan its resources accordingly to ensure cases are completed and decisions are rendered. In cases where utilities have not filed their applications in time to have rates in place prior to the effective date, the Board's practice has typically been to not allow the utility to retrospectively recover the amounts from the period where the interim order was in effect.[124] All applicants are aware of the Board's metrics. The process for an oral hearing is expected to take 235 days from the filing of the application to the issuance of the final decision, and 280 days until the issuance of the rate order.

OPG understood the timelines associated with filing a cost of service application and its witnesses confirmed that it was unlikely that the Board could have completed the process by January 1, 2014 given a September 27, 2013 filing date.[125] Even if a complete application had been filed in September, there was no scenario under which the proceeding could have been completed by January 1, 2014. OPG's proposal would result in the entire two-year increase for the previously regulated assets being recovered over a significantly shorter time period, resulting in a higher monthly bill impact increases exceeding the $5.36 and $5.94 identified in the two published Notices of Application. OPG estimated the impact of establishing effective dates of January 1, 2014 for the previously regulated assets and July 1, 2014 for the newly regulated assets was $649M or 43% over current payment amounts,[126] assuming an implementation date of September 1, 2014. A September 1, 2014 implementation date was used to calculate the magnitude of the increase during the oral phase of the proceeding; a November implementation date, assuming OPG's proposed payment amounts, would result in a percentage increase higher than 43%.

Ratepayers who made consumption decisions from January 1, 2014 to November 1, 2014, who thought they had already paid their electricity bills may be surprised to learn they will be responsible for additional costs, recovered through higher rates to be included on future bills until December 31, 2015. In addition, a January 1, 2014

[124] EB-2012-0165 (Sioux Lookout); EB-2013-0139 (Hydro Hawkesbury); EB-2012-0113 Centre Wellington; EB-2013-0130 Fort Frances
[125] Tr Vol 2 page 171
[126] Undertaking J3.10

effective date would result in some level of inter-generational inequity, to the extent customer profiles changed over that time.

The Board finds that the reasons this proceeding could not be completed by January 1, 2014 were almost entirely within OPG's control. OPG's witnesses indicated the earliest date the application would have been ready to file was August 2013. OPG's management made the decision to delay the filing further to include the newly prescribed hydroelectric assets. OPG indicated that it would not be practical or workable to file one application regarding the previously regulated assets first and then file a second application or update for the newly regulated assets at a later date. OPG's management had choices and made decisions regarding the timing, inclusion and exclusion of evidence. For example, OPG indicated its plans to file a separate application for disposition of deferral and variance account balances as of December 31, 2014;[127] an application the Board has yet to receive. In addition, OPG understands that options are available to separate issues in distinct applications for significant issues to expedite the hearing process. In fact, OPG asked the Board to consider a stand-alone Niagara Tunnel Project hearing. The Board responded to OPG's request in a letter dated April 13, 2012 and agreed that given the scale and complexity of the Niagara Tunnel Project, it was appropriate to consider a separate 2013-2014 payment amounts application. In the end, OPG decided not file a separate Niagara Tunnel application nor a payment amount application for 2013 rates.

When OPG filed its application on September 27, 2013, it was incomplete. A complete application was filed on December 5, 2013, less than one month before its proposed effective date.

The Board decided to issue a notice for the proceeding on October 25, 2013 based on the incomplete application in order to avoid further delay; however, the Board stated: "[t]he timing of any further procedural steps will be dependent on OPG's response to the items noted in this correspondence."

On December 6, 2013, one day after filing the complete application on December 5, 2013, OPG filed a major update to its application which required the issuance of a new notice, and essentially brought the proceeding back to step 1. New information continued to be filed, including updated evidence on the Darlington refurbishment

[127] Exh H1-1-1 page 1

project filed on July 2, 2014 which necessitated a delay of the oral hearing by several weeks.

The Board's decision is based on a balancing of the interests of the applicant and of the ratepayer. The timing of the application is solely in OPG's control, and the Board's metrics and policies regarding effective dates are well known. For the reasons provided above, the Board approves an effective date of November 1, 2014 for the previously regulated assets.

Effective Date for Newly Regulated Hydroelectric Payment Amounts

The Board has determined that the effective date for the final payment amounts shall be November 1, 2014 for the newly regulated hydroelectric facilities. As mandated by O. Reg. 53/05, the Board's regulation of the payment amounts for the newly regulated hydroelectric facilities commenced on July 1, 2014. From July 1, 2014 through October 31, 2014 the Board has determined that the payment amounts for the newly regulated hydroelectric facilities will remain HOEP, which is the amount that OPG actually recovered over that time period pursuant to the Board's interim rate order.

The Board accepts the arguments of the parties that argued that the Board is not legally required to set July 1, 2014 as the effective date for the final payment amounts applicable to the newly hydroelectric regulated facilities. O. Reg. 53/05 requires the Board to commence its payment regulation of the newly regulated hydroelectric facilities as of July 1, 2014; it does not require the Board to set the payment amounts at any particular level. In fact the regulation appears to contemplate that the effective date of the final payment order may well come after July 1, 2014: "[t]he order shall provide for the payment of amounts with respect to output that is generated at a generation facility referred to in paragraph 6 of section 2 [i.e. the newly regulated facilities] **during the period from July 1, 2014 to the day before the effective date of the order**."

The Board has determined that it is not legally required to set the effective date of the final order for the newly regulated hydroelectric facilities to July 1, 2014. The Board has decided that it would be inappropriate to do so. The Board orders that the effective date for the final payment order for the newly regulated hydroelectric facilities will be November 1, 2014.

OPG takes the position that given the September 2013 notice of the proposed amendment to O. Reg. 53/05 to regulate the newly regulated hydroelectric facilities, OPG could not have filed the application for the associated payment amounts any earlier than it did. OPG argues that it was dependent upon the Ministry's release of the proposal to amend the regulation in order to proceed with the application.

The draft regulation was published for comment in July 2013. The notice of the proposed amended regulation was made public in September 2013 and the regulation was filed in November 2013. The Board considers that an application could have been filed shortly after the draft regulation was published for comment (i.e. after July 2013). Indeed OPG did not wait for the regulation to be finalized before filing its original application.

It appears to the Board that OPG had various options available to it as to when it could have filed its application. In fact, the inclusion in the application of the newly regulated hydroelectric facilities was an issue of little controversy in this proceeding. One of the options it could have considered was to file the newly regulated hydroelectric portion of the application as an update to the payment amounts case which could have been filed earlier. Instead, OPG waited for the regulation to be issued as a draft before filing the entire payments amounts application. Other options were available as well, all of which could have resulted in finalized payment amounts at an earlier point in time. The Board has based its decision on the regulatory principle that rates should be set on a forward test year basis. The Board reiterates its reasons outlined in respect of the effective date for the nuclear and previously regulated hydroelectric payment amounts. The Board's position is that rates should be based on a forecast test year which establishes rates on a go forward basis, not retrospectively. This allows ratepayers to make informed consumption choices and provides utilities with certainty regarding revenue on a go-forward basis. OPG's evidence regarding when it could have filed its application is not so compelling as to move the Board off its practice of making rates effective in the month following the Board's final decision.

In the previous cost of service proceeding, the decision was issued on March 10, 2011 and the effective date was March 1, 2011. The IESO was able to implement the effective date through its billing processes without the necessity for shortfall payment amount riders to cover the period between March 1, 2011 and the date of the final payment amounts order. The Board expects that the same process can be accommodated in the current proceeding with a November 1, 2014 implementation for both the previously regulated and newly regulated assets.

The Board directs OPG to file with the Board, and copy to all intervenors, a draft payment amounts order which will include the final revenue requirement and payment amounts for the regulated hydroelectric and nuclear facilities, and reflect the findings made by the Board in this Decision. OPG should also include supporting schedules and a clear explanation of all calculations and assumptions used in deriving the payment amounts and the payment riders. The draft payment amounts order shall be filed by December 1, 2014.

OPG is directed to provide a full description of each deferral and variance account as part of the draft payment amounts order.

Board staff and intervenors shall respond to OPG’s draft payment order by December 8, 2014. OPG shall respond to any comments by Board staff and intervenors by December 12, 2014.

12 COST AWARDS

A number of intervenors were deemed eligible for cost awards in this proceeding: Association of Major Power Consumers in Ontario, Canadian Manufacturers & Exporters, Consumers Council of Canada, Energy Probe Research Foundation, Environmental Defence, Green Energy Coalition, Haudenosaunee Development Institute, Lake Ontario Waterkeeper, London Property Management Association, Retail Council of Canada, School Energy Coalition, Sustainability Journal and Vulnerable Energy Consumers Coalition.

At the oral hearing on June 12, 2014, the Board set out the process for intervenors to file their cost claims for the period ending June 11, 2014 for interim disposition. The cost award decision was issued on July 24, 2014.

A cost award decision for the period starting June 12, 2014 will be issued after the steps set out below are completed.

1. Intervenors eligible for cost awards shall file with the Board and forward to OPG their respective cost claims by December 15, 2014.
2. OPG shall file with the Board and forward to the relevant intervenors any objections to the costs claimed, including any objections to cost claims filed prior to the issuance of this Decision, by December 23, 2014.
3. Intervenors whose costs have been objected to, may file with the Board and forward to OPG any response to the objection by January 7, 2015.

OPG shall pay the Board's costs of and incidental to this proceeding upon receipt of the Board's invoice.

DATED at Toronto, November 20, 2014

ONTARIO ENERGY BOARD

Original signed by

Marika Hare
Presiding Member

Original signed by

Christine Long
Member

Original signed by

Allison Duff
Member

APPENDICES

TO

DECISION WITH REASONS

EB-2013-0321

ONTARIO POWER GENERATION INC.

Excerpt: Section 78.1 of the *Ontario Energy Board Act*, *1998*, S.O.1998, c.15 (Schedule B).

Payments to prescribed generator

78.1 (1) The IESO shall make payments to a generator prescribed by the regulations, or to the OPA on behalf of a generator prescribed by the regulations, with respect to output that is generated by a unit at a generation facility prescribed by the regulations. 2004, c. 23, Sched. B, s. 15.

Note: On January 1, 2015, the day named by proclamation of the Lieutenant Governor, subsection (1) is repealed and the following substituted: (See: 2014, c. 7, Sched. 23, ss. 7, 16)

Payments to prescribed generator

(1) The IESO shall make payments to a generator prescribed by the regulations with respect to output that is generated by a unit at a generation facility prescribed by the regulations. 2014, c. 7, Sched. 23, s. 7.

Payment amount

(2) Each payment referred to in subsection (1) shall be the amount determined,

(a) in accordance with the regulations to the extent the payment relates to a period that is on or after the day this section comes into force and before the later of,

(i) the day prescribed for the purposes of this subsection, and

(ii) the effective date of the Board's first order in respect of the generator; and

(b) in accordance with the order of the Board then in effect to the extent the payment relates to a period that is on or after the later of,

(i) the day prescribed for the purposes of this subsection, and

(ii) the effective date of the Board's first order under this section in respect of the generator. 2004, c. 23, Sched. B, s. 15.

Note: On January 1, 2015, the day named by proclamation of the Lieutenant Governor, subsection (2) is repealed and the following substituted: (See: 2014, c. 7, Sched. 23, ss. 7, 16)

Payment amount

(2) Each payment referred to in subsection (1) shall be the amount determined in accordance with the order of the Board then in effect. 2014, c. 7, Sched. 23, s. 7.

OPA may act as settlement agent

(3) The OPA may act as a settlement agent to settle amounts payable to a generator under this section. 2004, c. 23, Sched. B, s. 15.

Note: On January 1, 2015, the day named by proclamation of the Lieutenant Governor, subsection (3) is repealed. (See: 2014, c. 7, Sched. 23, ss. 7, 16)

Board orders

(4) The Board shall make an order under this section in accordance with the rules prescribed by the regulations and may include in the order conditions, classifications or practices, including rules respecting the calculation of the amount of the payment. 2004, c. 23, Sched. B, s. 15.

Fixing other prices

(5) The Board may fix such other payment amounts as it finds to be just and reasonable,

(a) on an application for an order under this section, if the Board is not satisfied that the amount applied for is just and reasonable; or

(b) at any other time, if the Board is not satisfied that the current payment amount is just and reasonable. 2004, c. 23, Sched. B, s. 15.

Burden of proof

(6) Subject to subsection (7), the burden of proof is on the applicant in an application made under this section. 2004, c. 23, Sched. B, s. 15.

Order

(7) If the Board on its own motion or at the request of the Minister commences a proceeding to determine whether an amount that the Board may approve or fix under this section is just and reasonable,

(a) the burden of establishing that the amount is just and reasonable is on the generator; and

(b) the Board shall make an order approving or fixing an amount that is just and reasonable. 2004, c. 23, Sched. B, s. 15.

Application

(8) Subsections (4), (5) and (7) apply only on and after the day prescribed by the regulations for the purposes of subsection (2). 2004, c. 23, Sched. B, s. 15.

Ontario Energy Board Act, 1998
Loi de 1998 sur la Commission de l'énergie de l'Ontario

ONTARIO REGULATION 53/05

PAYMENTS UNDER SECTION 78.1 OF THE ACT

Consolidation Period: From July 1, 2014 to the e-Laws currency date.

Last amendment: O. Reg. 312/13.

This Regulation is made in English only.

Definition

0.1 (1) In this Regulation,

"approved reference plan" means a reference plan, as defined in the Ontario Nuclear Funds Agreement, that has been approved by Her Majesty the Queen in right of Ontario in accordance with that agreement;

"nuclear decommissioning liability" means the liability of Ontario Power Generation Inc. for decommissioning its nuclear generation facilities and the management of its nuclear waste and used fuel;

"Ontario Nuclear Funds Agreement" means the agreement entered into as of April 1, 1999 by Her Majesty the Queen in right of Ontario, Ontario Power Generation Inc. and certain subsidiaries of Ontario Power Generation Inc., including any amendments to the agreement. O. Reg. 23/07, s. 1.

(2) For the purposes of this Regulation, the output of a generation facility shall be measured at the facility's delivery points, as determined in accordance with the market rules. O. Reg. 312/13. s. 1.

Prescribed generator

1. Ontario Power Generation Inc. is prescribed as a generator for the purposes of section 78.1 of the Act. O. Reg. 53/05, s. 1.

Prescribed generation facilities

2. The following generation facilities of Ontario Power Generation Inc. are prescribed for the purposes of section 78.1 of the Act:

1. The following hydroelectric generating stations located in The Regional Municipality of Niagara:
   i. Sir Adam Beck I.
   ii. Sir Adam Beck II.
   iii. Sir Adam Beck Pump Generating Station.
   iv. De Cew Falls I.
   v. De Cew Falls II.
2. The R. H. Saunders hydroelectric generating station on the St. Lawrence River.
3. Pickering A Nuclear Generating Station.
4. Pickering B Nuclear Generating Station.
5. Darlington Nuclear Generating Station.
6. As of July 1, 2014, the generation facilities of Ontario Power Generation Inc. that are set out in the Schedule. O. Reg. 53/05, s. 2; O. Reg. 23/07, s. 2; O. Reg. 312/13, s. 2.

Prescribed date for s. 78.1 (2) of the Act

3. April 1, 2008 is prescribed for the purposes of subsection 78.1 (2) of the Act. O. Reg. 53/05, s. 3.

4. REVOKED: O. Reg. 312/13, s. 3.

Deferral and variance accounts

5. (1) Ontario Power Generation Inc. shall establish a variance account in connection with section 78.1 of the Act that records capital and non-capital costs incurred and revenues earned or foregone on or after April 1, 2005 due to deviations from the forecasts as set out in the document titled "Forecast Information (as of Q3/2004) for Facilities Prescribed under Ontario Regulation 53/05" posted and available on the Ontario Energy Board website, that are associated with,

(a) differences in hydroelectric electricity production due to differences between forecast and actual water conditions;

(b) unforeseen changes to nuclear regulatory requirements or unforeseen technological changes which directly affect the nuclear generation facilities, excluding revenue requirement impacts described in subsections 5.1 (1) and 5.2 (1);

(c) changes to revenues for ancillary services from the generation facilities prescribed under section 2;

(d) acts of God, including severe weather events; and

(e) transmission outages and transmission restrictions that are not otherwise compensated for through congestion management settlement credits under the market rules. O. Reg. 23/07, s. 3.

(2) The calculation of revenues earned or foregone due to changes in electricity production associated with clauses (1) (a), (b), (d) and (e) shall be based on the following prices:

1. $33.00 per megawatt hour from hydroelectric generation facilities prescribed in paragraphs 1 and 2 of section 2.

2. $49.50 per megawatt hour from nuclear generation facilities prescribed in paragraphs 3, 4 and 5 of section 2. O. Reg. 23/07, s. 3.

(3) Ontario Power Generation Inc. shall record simple interest on the monthly opening balance of the account at an annual rate of 6 per cent applied to the monthly opening balance in the account, compounded annually. O. Reg. 23/07, s. 3.

(4) Ontario Power Generation Inc. shall establish a deferral account in connection with section 78.1 of the Act that records non-capital costs incurred on or after January 1, 2005 that are associated with the planned return to service of all units at the Pickering A Nuclear Generating Station, including those units which the board of directors of Ontario Power Generation Inc. has determined should be placed in safe storage. O. Reg. 23/07, s. 3.

(5) For the purposes of subsection (4), the non-capital costs include, but are not restricted to,

(a) construction costs, assessment costs, pre-engineering costs, project completion costs and demobilization costs; and

(b) interest costs, recorded as simple interest on the monthly opening balance of the account at an annual rate of 6 per cent applied to the monthly opening balance in the account, compounded annually. O. Reg. 23/07, s. 3.

5.1 REVOKED: O. Reg. 312/13, s. 3.

Nuclear liability deferral account

5.2 (1) Ontario Power Generation Inc. shall establish a deferral account in connection with section 78.1 of the Act that records, on and after the effective date of the Board's first order under 78.1 of the Act, the revenue requirement impact of changes in its total nuclear decommissioning liability between,

(a) the liability arising from the approved reference plan incorporated into the Board's most recent order under section 78.1 of the Act; and

(b) the liability arising from the current approved reference plan. O. Reg. 23/07, s. 3.

(2) Ontario Power Generation Inc. shall record interest on the balance of the account as the Board may direct. O. Reg. 23/07, s. 3.

5.3 REVOKED: O. Reg. 312/13, s. 3.

Nuclear development variance account

5.4 (1) Ontario Power Generation Inc. shall establish a variance account in connection with section 78.1 of the Act that records, on and after the effective date of the Board's first order under section 78.1 of the Act, differences between actual non-capital costs incurred and firm financial commitments made and the amount included in payments made under that section for planning and preparation for the development of proposed new nuclear generation facilities. O. Reg. 27/08, s. 1.

(2) Ontario Power Generation Inc. shall record interest on the balance of the account as the Board may direct. O. Reg. 27/08, s. 1.

Rules governing determination of payment amounts by Board

6. (1) Subject to subsection (2), the Board may establish the form, methodology, assumptions and calculations used in making an order that determines payment amounts for the purpose of section 78.1 of the Act. O. Reg. 53/05, s. 6 (1).

(2) The following rules apply to the making of an order by the Board that determines payment amounts for the purpose of section 78.1 of the Act:

1. The Board shall ensure that Ontario Power Generation Inc. recovers the balance recorded in the variance account established under subsection 5 (1) over a period not to exceed three years, to the extent that the Board is satisfied that,
   i. the revenues recorded in the account were earned or foregone and the costs were prudently incurred, and
   ii. the revenues and costs are accurately recorded in the account.
2. In setting payment amounts for the assets prescribed under section 2, the Board shall not adopt any methodologies, assumptions or calculations that are based upon the contracting for all or any portion of the output of those assets.
3. The Board shall ensure that Ontario Power Generation Inc. recovers the balance recorded in the deferral account established under subsection 5 (4). The Board shall authorize recovery of the balance on a straight line basis over a period not to exceed 15 years.
4. The Board shall ensure that Ontario Power Generation Inc. recovers capital and non-capital costs, and firm financial commitments incurred to increase the output of, refurbish or add operating capacity to a generation facility referred to in section 2, including, but not limited to, assessment costs and pre-engineering costs and commitments,
   i. if the costs and financial commitments were within the project budgets approved for that purpose by the board of directors of Ontario Power Generation Inc. before the making of the Board's first order under section 78.1 of the Act in respect of Ontario Power Generation Inc., or
   ii. if the costs and financial commitments were not approved by the board of directors of Ontario Power Generation Inc. before the making of the Board's first order under section 78.1 of the Act in respect of Ontario Power Generation Inc., if the Board is satisfied that the costs were prudently incurred and that the financial commitments were prudently made.

4.1 The Board shall ensure that Ontario Power Generation Inc. recovers the costs incurred and firm financial commitments made in the course of planning and preparation for the development of proposed new nuclear generation facilities, to the extent the Board is satisfied that,
   i. the costs were prudently incurred, and
   ii. the financial commitments were prudently made.

5. In making its first order under section 78.1 of the Act in respect of Ontario Power Generation Inc., the Board shall accept the amounts for the following matters as set out in Ontario Power Generation Inc.'s most recently audited financial statements that were approved by the board of directors of Ontario Power Generation Inc. before the effective date of that order:
   i. Ontario Power Generation Inc.'s assets and liabilities, other than the variance account referred to in subsection 5 (1), which shall be determined in accordance with paragraph 1.
   ii. Ontario Power Generation Inc.'s revenues earned with respect to any lease of the Bruce Nuclear Generating Stations.
   iii. Ontario Power Generation Inc.'s costs with respect to the Bruce Nuclear Generating Stations.
6. Without limiting the generality of paragraph 5, that paragraph applies to values relating to,
   i. capital cost allowances,
   ii. the revenue requirement impact of accounting and tax policy decisions, and

iii. capital and non-capital costs and firm financial commitments to increase the output of, refurbish or add operating capacity to a generation facility referred to in section 2.

7. The Board shall ensure that the balance recorded in the deferral account established under subsection 5.2 (1) is recovered on a straight line basis over a period not to exceed three years, to the extent that the Board is satisfied that revenue requirement impacts are accurately recorded in the account, based on the following items, as reflected in the audited financial statements approved by the board of directors of Ontario Power Generation Inc.,

   i. return on rate base,

   ii. depreciation expense,

   iii. income and capital taxes, and

   iv. fuel expense.

7.1 The Board shall ensure the balance recorded in the variance account established under subsection 5.4 (1) is recovered on a straight line basis over a period not to exceed three years, to the extent the Board is satisfied that,

   i. the costs were prudently incurred, and

   ii. the financial commitments were prudently made.

8. The Board shall ensure that Ontario Power Generation Inc. recovers the revenue requirement impact of its nuclear decommissioning liability arising from the current approved reference plan.

9. The Board shall ensure that Ontario Power Generation Inc. recovers all the costs it incurs with respect to the Bruce Nuclear Generating Stations.

10. If Ontario Power Generation Inc.'s revenues earned with respect to any lease of the Bruce Nuclear Generating Stations exceed the costs Ontario Power Generation Inc. incurs with respect to those Stations, the excess shall be applied to reduce the amount of the payments required under subsection 78.1 (1) of the Act with respect to output from the nuclear generation facilities referred to in paragraphs 3, 4 and 5 of section 2.

11. In making its first order under section 78.1 of the Act in respect of Ontario Power Generation Inc. that is effective on or after July 1, 2014, the following rules apply:

   i. The order shall provide for the payment of amounts with respect to output that is generated at a generation facility referred to in paragraph 6 of section 2 during the period from July 1, 2014 to the day before the effective date of the order.

   ii. The Board shall accept the values for the assets and liabilities of the generation facilities referred to in paragraph 6 of section 2 as set out in Ontario Power Generation Inc.'s most recently audited financial statements that were approved by the board of directors before the making of that order. This includes values relating to the income tax effects of timing differences and the revenue requirement impact of accounting and tax policy decisions reflected in those financial statements. O. Reg. 23/07, s. 4; O. Reg. 27/08, s. 2; O. Reg. 312/13, s. 4.

7. OMITTED (PROVIDES FOR COMING INTO FORCE OF PROVISIONS OF THIS REGULATION). O. Reg. 53/05, s. 7.

SCHEDULE

1. Abitibi Canyon.
2. Alexander.
3. Aquasabon.
4. Arnprior.
5. Auburn.
6. Barrett Chute.
7. Big Chute.
8. Big Eddy.
9. Bingham Chute.
10. Calabogie.
11. Cameron Falls.
12. Caribou Falls.
13. Chats Falls.
14. Chenaux.
15. Coniston.
16. Crystal Falls.
17. Des Joachims.
18. Elliott Chute.
19. Eugenia Falls.
20. Frankford.
21. Hagues Reach.
22. Hanna Chute.
23. High Falls.
24. Indian Chute.
25. Kakabeka Falls.
26. Lakefield.
27. Lower Notch.
28. Manitou Falls.
29. Matabitchuan.
30. McVittie.
31. Merrickville.
32. Meyersberg.
33. Mountain Chute.
34. Nipissing.
35. Otter Rapid.
36. Otto Holden.
37. Pine Portage.
38. Ragged Rapids.
39. Ranney Falls.

40. Seymour.
41. Sidney.
42. Sills Island.
43. Silver Falls.
44. South Falls.
45. Stewartville.
46. Stinson.
47. Trethewey Falls.
48. Whitedog Falls.

O. Reg. 312/13, s. 5.

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Exhibit A1-4-1
Attachment 2

Memorandum of Agreement

BETWEEN

Her Majesty the Crown In Right of Ontario (the "Shareholder")
And
Ontario Power Generation ("OPG")

Purpose

This document serves as the basis of agreement between Ontario Power Generation Inc. ("**OPG**") and its sole Shareholder, Her Majesty the Queen in Right of the Province of Ontario as represented by the Minister of Energy (the "**Shareholder**") on mandate, governance, performance, and communications. This agreement is intended to promote a positive and co-operative working relationship between OPG and the Shareholder.

OPG will operate as a commercial enterprise with an independent Board of Directors, which will at all times exercise its fiduciary responsibility and a duty of care to act in the best interests of OPG.

A. Mandate

1. OPG's core mandate is electricity generation. It will operate its existing nuclear, hydroelectric, and fossil generating assets as efficiently and cost-effectively as possible, within the legislative and regulatory framework of the Province of Ontario and the Government of Canada, in particular, the Canadian Nuclear Safety Commission. OPG will operate these assets in a manner that mitigates the Province's financial and operational risk.

2. OPG's key nuclear objective will be the reduction of the risk exposure to the Province arising from its investment in nuclear generating stations in general and, in particular, the refurbishment of older units. OPG will continue to operate with a high degree of vigilance with respect to nuclear safety.

3. OPG will seek continuous improvement in its nuclear generation business and internal services. OPG will benchmark its performance in these areas against CANDU nuclear plants worldwide as well as against the top quartile of private and publicly- owned nuclear electricity generators in North America. OPG's top operational priority will be to improve the operation of its existing nuclear fleet.

4. With respect to investment in new generation capacity, OPG's priority will be hydro- electric generation capacity. OPG will seek to expand, develop and/or improve its hydro- electric generation capacity. This will include expansion and redevelopment on its existing sites as well as the pursuit of new projects where feasible. These investments will be taken by OPG through partnerships or on its own, as appropriate.

5. OPG will not pursue investment in non-hydro-electric renewable generation projects unless specifically directed to do so by the Shareholder.

6. OPG will continue to operate its fossil fleet, including coal plants, according to normal commercial principles taking into account the Government's coal replacement policy and recognizing the role that fossil plants play in the Ontario electricity market, until government regulation and/or unanimous shareholder declarations require the closure of coal stations.

7. OPG will operate in Ontario in accordance with the highest corporate standards, including but not limited to the areas of corporate governance, social responsibility and corporate citizenship.

8. OPG will operate in Ontario in accordance with the highest corporate standards for environmental stewardship taking into account the Government's coal replacement policy.

B <u>Governance Framework</u>

The governance relationship between OPG and the Shareholder is anchored on the following:

1. OPG will maintain a high level of accountability and transparency:

   - OPG is an *Ontario Business Corporations Act* ("OBCA") company and is subject to all of the governance requirements associated with the OBCA.
   - OPG is also subject to the *Freedom of Information and Protection of Privacy Act*, the *Public Sector Salary Disclosure Act* and the *Auditor General Act*.
   - OPG's regulated assets will be subject to public review and assessment by the Ontario Energy Board.
   - OPG will annually appear before a committee of the Legislature which will review OPG's financial and operational performance.

2. The Shareholder may at times direct OPG to undertake special initiatives. Such directives will be communicated as written declarations by way of a Unanimous Shareholder Agreement or Declaration in accordance with Section 108 of the OBCA, and be made public within a reasonable timeframe.

C. <u>Generation Performance and Investment Plans</u>

1. OPG will annually establish 3 –5 year performance targets based on operating and financial results as well as major project execution. Key measures are to be agreed upon with the Shareholder and the Minister of Finance. These performance targets will be benchmarked against the

performance of the top quartile of electricity generating companies in North America.

2. Benchmarking will need to take account of key specific operational and technology factors including the operation of CANDU reactors worldwide, the role that OPG's coal plants play in the Ontario electricity market with respect to load following, and the Government of Ontario's coal replacement policy.

3. OPG will annually prepare a 3 – 5 year investment plan for new projects.

4. Once approved by OPG's Board of Directors, OPG's annual performance targets and investment plan will be submitted to the Shareholder and the Minister of Finance for concurrence.

D. Financial Framework

1. As an OBCA corporation with a commercial mandate, OPG will operate on a financially sustainable basis and maintain the value of its assets for its shareholder, the Province of Ontario.

2. As a transition to a sustainable financial model, any significant new generation project approved by the OPG Board of Directors and agreed to by the Shareholder may receive financial support from the Province of Ontario, if and as appropriate.

E. Communication and Reporting

1. OPG and the Shareholder will ensure timely reports and information on major developments and issues that may materially impact the business of OPG or the interests of the Shareholder. Such reporting from OPG should be on an immediate or, at minimum, an expedited basis where an urgent material human safety or system reliability matter arises.

2. OPG will ensure the Minister of Finance receives timely reports and information on multi-year and annual plans and major developments that may have a material impact on the financial performance of OPG or the Shareholder.

3. The OPG Board of Directors and the Minister of Energy will meet on a quarterly basis to enhance mutual understanding of interrelated strategic matters.

4. OPG's Chair, President and Chief Executive Officer and the Minister of Energy will meet on a regular basis, approximately nine times per year.

5. OPG's Chair, President and Chief Executive Officer and the Minister of Finance will meet on an as needed basis.

6. OPG's senior management and senior officials of the Ministry of Energy and the Ministry of Finance will meet on a regular and as needed basis to discuss ongoing issues and clarify expectations or to address emergent issues.

7. OPG will provide officials in the Ministry of Energy and the Ministry of Finance with multi-year and annual business planning information, quarterly and monthly financial reports and briefings on OPG's operational and financial performance against plan.

8. In all other respects, OPG will communicate with government ministries and agencies in a manner typical for an Ontario corporation of its size and scope.

F. Review of this Agreement

This agreement will be reviewed and updated as required.

Dated: the 17th day of August, 2005

On Behalf of OPG:	On Behalf of the Shareholder:
Original signed by:	Original signed by:
Jake Epp Chairman Board of Directors	Her Majesty the Queen in Right of the Province of Ontario as represented by the Minister of Energy, Dwight Duncan

APPROVALS

Updated to reflect the Second Impact Statement (Ex. N2-1-1)

In this Application, OPG is seeking the following specific approvals:

- The approval of a revenue requirement of $1,757.8M for the previously regulated hydroelectric facilities and a revenue requirement of $6,395.4M for the nuclear facilities for the period of January 1, 2014 through December 31, 2015 as set out in Ex. N2-1-1.

- The approval of an 18 month revenue requirement of $853.2M for the newly regulated hydroelectric facilities for the period of July 1, 2014 through December 31, 2015, calculated as one half of a 2014 revenue requirement of $554.6M plus a 2015 revenue requirement of $575.9, as set out in Ex. N2-1-1.

- The approval of a rate base of $5,128.0M and $5,084.6M for the previously regulated hydroelectric facilities for the years 2014 and 2015, respectively; a rate base of $2,511.5M and $2,528.2M for the newly regulated hydroelectric facilities for the years 2014 and 2015, respectively; and $3,706.7M and $3,659.0M for the nuclear facilities for the years 2014 and 2015, respectively, as summarized in Ex. B1-1-1.

- Approval of a production forecast of 41.1 TWh for 2014 and 2015 for the previously regulated hydroelectric facilities, a production forecast of 17.9 TWh for July 1, 2014 to December 31, 2015 for the newly regulated hydroelectric facilities; and 94.6 TWh for 2014 and 2015 for the nuclear facilities. The production forecasts are presented in Ex. E1-1-1 and Ex. E2-1-1 and updated in Ex. N1-1-1 and N2-1-1.

- Approval of a deemed capital structure of 53 per cent debt and 47 per cent equity and a combined rate of return on rate base to be determined using data available for the three months prior to the effective date of the payment amounts order, in accordance with the Board's Cost of Capital Report, and currently set at 9.36 per cent for 2014

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and forecast at 9.53 per cent for 2014 and 2015, as presented in Ex. N2-1-1.

- Approval of a payment amount for the previously regulated hydroelectric facilities, of \$42.75/MWh effective January 1, 2014 for the average hourly net energy production (MWh) from the previously regulated hydroelectric facilities in any given month (the "hourly volume") for each hour of that month. Production over the hourly volume will receive the market price from the Independent Electricity System Operator ("IESO")-administered energy market adjusted as described at Ex. E1-2-1. Where production from the previously regulated hydroelectric facilities is less than the hourly volume, OPG's revenues will be adjusted by the difference between the hourly volume and the actual net energy production at the market price from the IESO-administered market adjusted as described at Ex. E1-2-1. The calculation of the payment amount for the previously regulated hydroelectric facilities is set out in Ex. I1-2-1 as updated in Ex. N2-1-1.

- Approval of a payment amount for the newly regulated hydroelectric facilities, of \$47.57/MWh effective July 1, 2014 for the average hourly net energy production (MWh) from the newly regulated facilities in any given month (the "hourly volume") for each hour of that month. Production over the hourly volume will receive the market price from the Independent Electricity System Operator ("IESO")-administered energy market adjusted as described at Ex. E1-2-1. Where production from the newly regulated hydroelectric facilities is less than the hourly volume, OPG's revenues will be adjusted by the difference between the hourly volume and the actual net energy production at the market price from the IESO-administered market adjusted as described at Ex. E1-2-1. The calculation of the payment amount for the newly regulated hydroelectric facilities is set out in Ex. I1-2-1 as updated in Ex. N2-1-1.

- Approval of a payment amount for the nuclear facilities, of \$67.60/MWh effective January 1, 2014.

- Approval for recovery of the audited December 31, 2013 balances of the Hydroelectric Incentive Mechanism, Surplus Baseload Generation and Capacity Refurbishment-Hydroelectric variance accounts for the previously regulated hydroelectric facilities, of $127.0M, as described in Ex. H1-1-2, as updated in Ex. N2-1-1, and disposition, beginning January 1, 2015, at a rate of $3.36/MWh applied to the output from the previously regulated hydroelectric facilities.

- Approval for recovery of the audited December 31, 2013 balance of the Nuclear Development Variance Account and a portion of the balance of the Capacity Refurbishment Variance Account - Nuclear for the nuclear facilities, of $62.2M as described in Ex. H1-2-1, as updated in Ex. N2-1-1, and disposition, beginning January 1, 2015, at a rate of $1.35/MWh applied to the output from the nuclear facilities.

- Approval to establish, re-establish or continue variance and deferral accounts as follows:
    - A variance account to record the deviation from forecast revenues associated with differences in regulated hydroelectric electricity production due to differences between forecast and actual water conditions.
    - A variance account to record the deviation from forecast net revenues for ancillary services from the regulated hydroelectric facilities and the nuclear facilities.
    - A variance account to record the financial impact of foregone production at its regulated hydroelectric facilities due to surplus baseload generation.
    - A variance account to record interest and amortization of the accumulations up to year end 2013 of 50 per cent of the Hydroelectric Incentive Mechanism net revenues above amounts underpinning the EB-2010-0008 revenue requirement as a credit to ratepayers, proposed to be terminated December 31, 2015.
    - A variance account to record the deviation from forecast capital and non-capital costs and firm financial commitments associated with work to increase

the output of, refurbish or add operating capacity to a regulated facility.

- A variance account to record the deviation from forecast costs incurred and firm financial commitments made in the course of planning and preparation for the development of proposed new nuclear generation facilities.
- A deferral account to record the revenue requirement impact of any change in the nuclear decommissioning liability resulting from an approved reference plan as defined in the Ontario Nuclear Funds Agreement.
- A variance account to capture the tax impact of changes in tax rates, rules and assessments.
- A variance account to record the variance between the tax loss mitigation amount which underpins the EB-2007-0905 Payment Amounts Order and the tax loss amount resulting from the re-analysis of the prior period tax returns based on the OEB's directions in EB-2007-0905 Decision with Reasons as to the re-calculation of those tax losses, to be terminated December 31, 2014.
- A variance account to capture differences between forecast and actual costs and revenues related to the lease of the Bruce nuclear facilities and associated tax effects.
- A variance account to capture depreciation cost differences due to a revised service life, for accounting purposes, of the Pickering nuclear facility.
- A variance account to record the difference between forecast and actual pension and other post-employment benefit costs and associated tax effects related to the regulated hydroelectric and nuclear facilities.
- A deferral account to record the transition and implementation impacts associated with the adoption of the Generally Accepted Accounting Principle of the United States ("USGAAP"), to be terminated December 31, 2014.
- Variance accounts to record the over/under recovery amounts for the hydroelectric variance and deferral accounts and nuclear variance and deferral accounts, respectively.

Evidence supporting the continuation of existing variance and deferral accounts and the creation of new ones is provided in Ex. H1-3-1.

- In respect of the Darlington Refurbishment Project ("DRP") OPG seeks the following as described in Ex. D2-2-1:
  - A finding that OPG's commercial and contracting strategies for the DRP are reasonable;
  - A finding that the proposed capital expenditures of $837.4M in 2014 and $631.8M in 2015 are reasonable;
  - Approval of OM&A expenditures of $6.6M in 2014 and $18.2M in 2015 (Ex. F2-7-1, Ex. N2-1-1);
  - Approval of in-service additions to rate base of $5.0M in 2012, $104.2M in 2013, $18.7M in 2014, and $209.4M in 2015 for new facilities and related 2014 and 2015 depreciation expense; and
  - Approval to recover the capital cost portion of the actual audited nuclear balance in the Capacity Refurbishment Variance Account as at December 31, 2013 of $5.7M.

- An order from the OEB declaring OPG's current payment amounts for previously regulated hydroelectric and nuclear facilities interim as of January 1, 2014, if the order or orders approving the payment amounts are not implemented by January 1, 2014.

- An order from the OEB declaring OPG's current payment amounts for the newly regulated hydroelectric facilities interim as of July 1, 2014, if the order or orders approving the payment amounts are not implemented by July 1, 2014.

PROCEDURAL DETAILS INCLUDING LISTS OF PARTIES AND WITNESSES

THE PROCEEDING

OPG filed its application for new payment amounts on September 27, 2013. On October 25, 2014, the Board issued a Notice of Application and Oral Hearing which was published in accordance with the Board's direction.

The key milestones in the proceeding are listed below:

- The application, as filed, was incomplete and OPG filed additional pre-filed evidence on December 5, 2013.
- OPG filed an impact statement on December 6, 2013 (Exhibit N1) that updated the application to reflect material changes in costs and production forecasts for the 2014-2015 period that are included in OPG's 2014-2016 business plan.
- An interim order declaring payment amounts for the previously regulated hydroelectric facilities and nuclear facilities interim effective January 1, 2014, and for the newly regulated hydroelectric facilities interim effective July 1, 2014, was issued on December 17, 2013.
- The Board issued Procedural Order No.1 on December 20, 2013. Given the material change in customer impact reported in the Exhibit N1 update filed on December 6, 2013, the Board determined that further notice was required. Procedural Order No. 1 also provided a draft issues list and made provision for submissions on issues and OPG's request for confidential treatment of certain information. The procedural order also set out a schedule for interrogatories.
- The final unprioritized issues list was issued along with Procedural Order No. 3 on February 19, 2014.
- Interrogatories were filed by Board staff on February 21, 2014 and by intervenors on February 28, 2014. The majority of responses were filed on March 19, 2014.
- Procedural Order No. 5, issued on April 3, 2014, set out the schedule for the settlement conference and oral hearing.
- A technical conference was held April 22 and 23, 2014. A second technical conference, related to the Darlington Refurbishment Project, was held July 8 and 9, 2014.
- A motion hearing was held on May 9, 2014.

- A second impact statement was filed on May 16, 2014 (Exhibit N2) to update the application to reflect material changes in costs and production forecasts that had arisen since the first impact statement was filed.
- A settlement conference was held May 21, 2014 to May 26, 2014, however no settlement was achieved.
- The final prioritized issues list was issued along with Procedural Order No. 10 on June 4, 2014.
- The oral hearing took place on 16 days during the period June 12, 2014 to July 18, 2014.
- OPG filed its Argument-in-Chief on July 28, 2014.
- Board staff filed its submission on August 19, 2014 and intervenors filed their submissions on August 26, 2014 except the Society of Energy Professional who filed on August 29, 2014.
- OPG's reply argument was filed on September 10, 2014.

Fourteen procedural orders were issued during the course of the proceeding, some dealing with the schedule of the proceeding and prioritization of the issues list, but many dealing with matters of confidentiality, including submissions and decisions on requests for confidential treatment of documents, and submissions.

PARTICIPANTS

Below is a list of participants and their representatives that were active either at the oral hearing or at another stage of the proceeding.

Ontario Power Generation Inc.	Charles Keizer Crawford Smith Carlton Mathias Andrew Barrett Colin Anderson

Board Counsel and Staff	Michael Millar Violet Binette Ben Baksh Richard Battista Russell Chute Keith Ritchie Duncan Skinner
Association of Major Power Consumers in Ontario	David Crocker Hamza Mortage Shelley Grice
Canadian Manufacturers & Exporters	Peter Thompson Vince DeRose Emma Blanchard
Consumers Council of Canada	Julie Girvan
Energy Probe Research Foundation	David MacIntosh Lawrence Schwartz
Environmental Defence	Kent Elson
Green Energy Coalition	David Poch
Haudenosaunee Development Institute	Aaron Detlor
Independent Electricity System Operator	Glenn Zacher Jessica Savage Tam Wagner
Lake Ontario Waterkeeper	Pippa Feinstein
London Property Management Association	Randy Aiken

Ontario Power Authority	Fred Cass Miriam Heinz
Power Workers' Union	Richard Stephenson Alfredo Bertolotti
Retail Council of Canada	Travis Allan
School Energy Coalition	Jay Shepherd Mark Rubenstein Mark Garner
Society of Energy Professionals	Mike Belmore Russ Houldin
Sustainability-Journal	Ron Tolmie
Vulnerable Energy Consumers Coalition	Michael Janigan James Wightman

In addition to the above, Enwin Utilities Ltd., HQ Energy Marketing Inc. and Shell Energy North America (Canada) Inc. were registered intervenors in this proceeding. Marc Raymond and the Ministry of Energy were registered observers in this proceeding.

WITNESSES

The following OPG employees appeared as witnesses.

Andrew Barrett	Vice President, Regulatory Affairs
John Mauti	Vice President, Business Planning & Reporting
Nicolle Butcher	Project Executive, Business Transformation (Acting)
Mario Mazza	Vice President, Strategy & Business Support, Hydro

	Thermal Operations
Robby Sohi	Director, Plant Engineering Services, Hydro Thermal Operations
Bill Wilbur	Director, Generation & Revenue Planning, Commercial Operations & Environment Business Unit
Chris Young	Vice President, Hydroelectric and Thermal Project Execution
Laurie Swami	Vice President, Nuclear Services
Carla Carmichael	Vice President, Nuclear Finance
John Blazanin	Director, Controllership, Nuclear Finance
Jamie Lawrie	Project Director
Jason Fitzsimmons	Vice President, Health and Safety, Labour and Employee Relations
Ali Earle	Director, Human Resources
Lubna Ladak	Director, Controllership
Alex Kogan	Director, Business Planning and Regulatory Finance
Dietmar Reiner	Senior Vice President, Nuclear Projects
Gary Rose	Director of Refurbishment, Planning and Control

OPG also called the following expert witness: Roger Ilsley of R I Geotechnical Inc., Richard Chaykowski of Queen’s University, Kathleen McShane of Foster Associates Inc., Eric Gould of Modus Strategic Solutions and John Reed of Concentric Energy Advisors.

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FINAL ISSUES LIST (REPRIORITIZED)

1. GENERAL

1.1 Primary - Has OPG responded appropriately to all relevant Board directions from previous proceedings?

1.2 Primary - Are OPG's economic and business planning assumptions for 2014-2015 appropriate?

1.3 Secondary - Has OPG appropriately applied USGAAP accounting requirements, including identification of all accounting treatment differences from its last payment order proceeding?

1.4 Oral Hearing: Is the overall increase in 2014 and 2015 revenue requirement reasonable given the overall bill impact on customers?

2. RATE BASE

2.1 Primary - Are the amounts proposed for rate base appropriate?

3. CAPITAL STRUCTURE AND COST OF CAPITAL

3.1 Primary - What is the appropriate capital structure and rate of return on equity for the currently regulated facilities and newly regulated facilities?

3.2 Secondary - Are OPG's proposed costs for its long-term and short-term debt components of its capital structure appropriate?

4. CAPITAL PROJECTS

Regulated Hydroelectric

4.1 Secondary - Do the costs associated with the regulated hydroelectric projects that are subject to section 6(2)4 of O. Reg. 53/05 and proposed for recovery (excluding the Niagara Tunnel Project), meet the requirements of that section?

4.2 Secondary - Are the proposed regulated hydroelectric capital expenditures and/or financial commitments reasonable?

4.3 Secondary - Are the proposed test period in-service additions for regulated hydroelectric projects (excluding the Niagara Tunnel Project) appropriate?
4.4 Primary - Do the costs associated with the Niagara Tunnel Project that are subject to section 6(2)4 of O. Reg. 53/05 and proposed for recovery, meet the requirements of that section?
4.5 Primary - Are the proposed test period in-service additions for the Niagara Tunnel Project reasonable?

Nuclear

4.6 Primary (reprioritized) - Do the costs associated with the nuclear projects that are subject to section 6(2)4 of O. Reg. 53/05 and proposed for recovery, meet the requirements of that section?
4.7 Oral Hearing: Are the proposed nuclear capital expenditures and/or financial commitments reasonable?
4.8 Primary (reprioritized) - Are the proposed test period in-service additions for nuclear projects (excluding those for the Darlington Refurbishment Project) appropriate?
4.9 Primary - Are the proposed test period in-service additions for the Darlington Refurbishment Project) appropriate?
4.10 Primary - Are the proposed test period capital expenditures associated with the Darlington Refurbishment Project reasonable?
4.11 Oral Hearing: Are the commercial and contracting strategies used in the Darlington Refurbishment Project reasonable?
4.12 Primary - Does OPG’s nuclear refurbishment process align appropriately with the principles stated in the Government of Ontario’s Long Term Energy Plan issued on December 2, 2013?

5. PRODUCTION FORECASTS

Regulated Hydroelectric

5.1 Secondary - Is the proposed regulated hydroelectric production forecast appropriate?
5.1(a) Primary - Could the storage of energy improve the efficiency of hydroelectric generating stations?
5.2 Primary (reprioritized) - Is the estimate of surplus baseload generation appropriate?

5.3 Secondary - Has the incentive mechanism encouraged appropriate use of the regulated hydroelectric facilities to supply energy in response to market prices?

5.4 Primary - Is the proposed new incentive mechanism appropriate?

Nuclear

5.5 Primary - Is the proposed nuclear production forecast appropriate?

6. OPERATING COSTS

Regulated Hydroelectric

6.1 Oral Hearing: Is the test period Operations, Maintenance and Administration budget for the regulated hydroelectric facilities appropriate?

6.2 Oral Hearing: Is the benchmarking methodology reasonable? Are the benchmarking results and targets flowing from those results for the regulated hydroelectric facilities reasonable?

Nuclear

6.3 Oral Hearing: Is the test period Operations, Maintenance and Administration budget for the nuclear facilities appropriate?

6.4 Oral Hearing: Is the benchmarking methodology reasonable? Are the benchmarking results and targets flowing from those results for the nuclear facilities reasonable?

6.5 Secondary - Is the forecast of nuclear fuel costs appropriate? Has OPG responded appropriately to the suggestions and recommendations in the Uranium Procurement Program Assessment report?

6.6 Primary (reprioritized) - Are the test period expenditures related to continued operations for Pickering Units 5 to 8 appropriate?

6.7 Primary - Is the test period Operations, Maintenance and Administration budget for the Darlington Refurbishment Project appropriate?

Corporate Costs

6.8 Oral Hearing: Are the 2014 and 2015 human resource related costs (wages, salaries, benefits, incentive payments, FTEs and pension costs) appropriate?

6.9 Oral Hearing: Are the corporate costs allocated to the regulated hydroelectric and nuclear businesses appropriate?

6.10 Oral Hearing: Are the centrally held costs allocated to the regulated hydroelectric business and nuclear business appropriate?

Depreciation

6.11 Secondary - Is the proposed test period depreciation expense appropriate?

6.12 Secondary - Are the depreciation studies and associated proposed changes to depreciation expense appropriate?

Income and Property Taxes

6.13 Primary (reprioritized) - Are the amounts proposed to be included in the test period revenue requirement for income and property taxes appropriate?

Other Costs

6.14 Secondary - Are the asset service fee amounts charged to the regulated hydroelectric and nuclear businesses appropriate?

6.15 Secondary - Are the amounts proposed to be included in the test period revenue requirement for other operating cost items appropriate?

7. OTHER REVENUES

Regulated Hydroelectric

7.1 Secondary - Are the proposed test period revenues from ancillary services, segregated mode of operation and water transactions appropriate?

Nuclear

7.2 Secondary - Are the forecasts of nuclear business non-energy revenues appropriate?

Bruce Nuclear Generating Station

7.3 Secondary - Are the test period costs related to the Bruce Nuclear Generating Station, and costs and revenues related to the Bruce lease appropriate?

8. NUCLEAR WASTE MANAGEMENT AND DECOMMISSIONING LIABILITIES

8.1 Primary (reprioritized) - Is the revenue requirement methodology for recovering nuclear liabilities in relation to nuclear waste management and decommissioning costs appropriate? If not, what alternative methodology should be considered?

8.2 Primary (reprioritized) - Is the revenue requirement impact of the nuclear liabilities appropriately determined?

9. DEFERRAL AND VARIANCE ACCOUNTS

9.1 Secondary - Is the nature or type of costs recorded in the deferral and variance accounts appropriate?

9.2 Secondary - Are the balances for recovery in each of the deferral and variance accounts appropriate?

9.3 Secondary - Are the proposed disposition amounts appropriate?

9.4 Secondary - Is the disposition methodology appropriate?

9.5 Secondary - Is the proposed continuation of deferral and variance accounts appropriate?

9.6 Oral Hearing: Is OPG's proposal to not clear deferral and variance account balances in this proceeding (other than the four accounts directed for clearance in EB-2012-0002) appropriate?

9.7 Primary (reprioritized) - Is OPG's proposal to make existing hydroelectric variance accounts applicable to the newly regulated hydroelectric generation facilities appropriate?

9.8 Secondary - Is the proposal to discontinue the Hydroelectric Incentive Mechanism Variance Account appropriate?

9.9 Primary (reprioritized) - What other deferral accounts, if any, should be established for OPG?

10. REPORTING AND RECORD KEEPING REQUIREMENTS

10.1 Secondary - What additional reporting and record keeping requirements should be established for OPG?

11. METHODOLOGIES FOR SETTING PAYMENT AMOUNTS

11.1 Oral Hearing: Has OPG responded appropriately to Board direction on establishing incentive regulation?

11.2 Secondary - Is the design of the regulated hydroelectric and nuclear payment amounts appropriate?

11.3 Oral Hearing: To what extent, if any, should OPG implement mitigation of any rate increases determined by the Board? If mitigation should be implemented, what is the appropriate mechanism that should be used?

12. IMPLEMENTATION

12.1 Oral Hearing: Are the effective dates for new payment amounts and riders appropriate?

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Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

EB-2014-0043

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, (Schedule B);

AND IN THE MATTER OF an application by Enbridge Gas Distribution Inc. for an order or orders approving or fixing rates for the sale, distribution, transmission and storage of gas.

BEFORE: Marika Hare
Presiding Member

Allison Duff
Member

DECISION AND ORDER
April 10, 2014

Enbridge Gas Distribution inc. ("Enbridge") filed an application with the Ontario Energy Board (the "Board") on February 13, 2014 under section 36 of the *Ontario Energy Board Act*, *1998*, S.O. 1998, c. 15, (Schedule B) for an order giving final approval for Rider C commodity unit rates that were approved on an interim basis in the Board's EB-2013-0406 Decision and Interim Order, dated December 20, 2013.

Enbridge's EB-2013-0406 application was filed in accordance with the Quarterly Rate Adjustment Mechanism ("QRAM") process for a rate adjustment relating to gas costs effective January 1, 2014 (the "QRAM proceeding"). In that application, among other things, Enbridge proposed a refund of $10.1 million from the Gas Acquisition – Commodity and the Gas in Inventory Re-valuation components of the Purchased Gas Variance Account ("PGVA"). Enbridge indicated that the $10.1 million should have been refunded to sales (i.e. system gas) service customers in prior QRAMs but was not, due to errors in the calculation of account balances. Enbridge described the errors as "mechanical" as the formulae within Excel spreadsheet models were incorrect.

The Board's decision in the QRAM proceeding for January 1 gas costs was issued by delegated authority. The decision indicated that the proposed refund of $10.1 million raised possible issues of rate retroactivity that were not typically dealt with by a delegated authority; therefore, a refund of $10.1 million, contained in the commodity components of Rider C, was approved, but on an interim basis, subject to a separate application to be filed by Enbridge.

Enbridge filed this application to finalize the interim Rider C. As part of its application Enbridge filed the Decision and Order of the Board in the QRAM proceeding as well as the evidence on the record in that proceeding. The Board granted intervenor status to all intervenors in the QRAM proceeding and provided parties with the opportunity to file comments and interrogatories. All parties were invited to make submissions on whether the $10.1 million refund constitutes retroactive ratemaking.

The Industrial Gas Users Association ("IGUA") and Board staff filed submissions on March 6, 2014. Each supported Enbridge's proposal to refund the money.

Board Findings

Based on the facts of the case, the Board agrees with Enbridge and the parties that the money should be refunded to customers.

Enbridge has acknowledged that it committed an unintentional error which resulted in over $10 million being incorrectly recovered from customers.

The parties support Enbridge's proposal and there is no disadvantage to customers from this approach.

The Board acknowledges that Enbridge's QRAM orders were final in EB-2012-0352 and EB-2013-0045 and that Rider C is an out-of-period adjustment. However, the Board has considered the facts of this case in the context of the *MCI Telecommunications v. Public Service Commission*[1], a United States decision referenced in Board staff's submission. While the facts of the cases are distinguishable, the conclusions are the same. An out-of-period adjustment can be justified if it ensures a utility does not profit on account of its own errors.

[1] *MCI Telecommunications v. Public Service Commission*, 840 P.2d 765 (Utah 1992)

THE BOARD ORDERS THAT:

1. The Rider C commodity unit rates approved on an interim basis in the Board's EB-2013-0406 Decision and Interim Order, dated December 20, 2013, are considered final.

COST AWARDS

The Board will issue a separate decision on cost awards once the following steps are completed:

1. IGUA shall submit their cost claims no later than 7 days from the date of issuance of this Decision and Order.

2. Enbridge shall file with the Board and forward to IGUA any objections to the claimed costs within 21 days from the date of issuance of this Decision and Order.

3. IGUA shall file with the Board and forward to Enbridge and response to any objections for cost claims within 28 days from the date of issuance of this Decision and Order.

4. Enbridge shall pay the Board's costs incidental to this proceeding upon receipt of the Board's invoice.

All filings to the Board must quote the file number, **EB-2014-0043**, be made electronically through the Board's web portal at https://www.pes.ontarioenergyboard.ca/eservice/, in searchable / unrestricted PDF format. Two paper copies must also be filed at the Board's address provided below. Filings must clearly state the sender's name, postal address and telephone number, fax number and e-mail address. Parties must use the document naming conventions and document submission standards outlined in the RESS Document Guideline found at http://www.ontarioenergyboard.ca/OEB/Industry. If the web portal is not available parties may email their documents to the address below. Those who do not have internet access are required to submit all filings on a CD in PDF format, along with two paper copies. Those who do not have computer access are required to file 7 paper copies.

All communications should be directed to the attention of the Board Secretary at the address below, and be received no later than 4:45 p.m. on the required date.

With respect to distribution lists for all electronic correspondence and materials related to this proceeding, parties must include the Case Manager, Daniel Kim at daniel.kim@ontarioenergyboard.ca and Board Counsel, Maureen Helt at maureen.helt@ontarioenergyboard.ca.

ADDRESS

Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, 27th Floor
Toronto ON   M4P 1E4
Attention: Board Secretary

E-mail: boardsec@ontarioenergyboard.ca
Tel: 1-888-632-6273 (Toll free)
Fax: 416-440-7656

DATED at Toronto, April 10, 2014

ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

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Ontario Energy Board | **Commission de l'énergie de l'Ontario**

EB-2009-0113

IN THE MATTER OF the *Ontario Energy Board Act, 1998,* S.O. 1998, c.15, (Schedule B);

AND IN THE MATTER OF an application by North Bay Hydro Distribution Limited for an order approving just and reasonable rates to be effective July 1, 2009.

BEFORE: **Ken Quesnelle**
Presiding Member

DECISION AND ORDER

September 8, 2009

North Bay Hydro Distribution Limited (North Bay) filed an application with the Ontario Energy Board on April 21, 2009, under section 78 of the *Ontario Energy Board Act, 1998*, S.O. 1998, c.15, Schedule B), seeking approval for a proposed schedule of rate riders to be effective July 1, 2009. The Board assigned file number EB-2009-0113 to the application.

The Board issued a Notice of Application and Written Hearing on May 26, 2009. The Vulnerable Energy Consumers Coalition (VECC) and Hydro One Networks Inc. (Hydro One) were approved as intervenors.

Procedural Order No. 1 was issued on June 18, 2009. The Board made provision for written interrogatories and for submissions. VECC and Board staff filed interrogatories and made submissions. Hydro One filed interrogatories, but made no submission. North Bay's reply submission was filed on August 11, 2009. The full record is available at the Board's offices.

THE APPLICATION

Background

North Bay requested disposition of a total of $2,029,825 of its Retail Service Variance Account ("RSVA") balances as of December 31, 2008. North Bay also requested the disposition of carrying charges associated with the above balances of $17,149 for the period of January 1, 2009 to through June 30, 2009. The total overall requested disposition is $2,046,974.

In its application, North Bay stated that Board Regulatory Audit staff initiated a review of North Bay's Account 1588 (RSVA Power) in 2008 due to the balances associated with this account being higher than the industry average. On December 2, 2008, following the review, Board Regulatory Audit staff issued a final letter and stated that North Bay should correct the entries in Account 1588 in accordance with the Account Procedures Handbook.

Following the Board Regulatory Audit staff review, North Bay engaged the services of a consultant to conduct a review of all five RSVAs[1]. As a result, North Bay's consultant,

1 Account 1580, Account 1582, Account 1584, Account 1586 and Account 1588

E360, provided the corrected balances which covered the period May 2002 to December 2008 and also recalculated the carrying charges. These corrected RSVA balances and carrying charges had been audited by North Bay's external financial Auditors, BDO Dunwoody LLP.

Board staff had no concerns with the calculations. VECC made no comments on the calculation of the balances; however VECC took the position that an adjustment regarding the allocation for the Account 1588 Global Adjustment sub-account is required.

VECC noted that North Bay proposed to allocate the total balances of Account 1588 to each class. Since the Global Adjustment sub-account is established to track the Global Adjustment for non-RPP customers only, VECC submitted that the balances from the Global Adjustment sub-account should be recovered based on the non-RPP load associated with each class. VECC further submitted that the rate riders should be based on the response to VECC's interrogatory[2] which reflected VECC's proposed form of recovery. In its reply submission, North Bay accepted the rate riders as submitted by VECC.

Significance of the Balance

North Bay submitted that the outstanding balance of $2,029,825.46 is of great significance to it and provided the following comments in that regard[3]:

a) The RSVA balances represent true costs that were incurred by the Applicant but were inadvertently not passed along to customers for recovery;
b) Using deferral accounts to identify and track costs for recovery at a future period is a standard industry practice;
c) The balance of $2,029,825.46 (comprised of $2,110,574 principal less $80,749 in a credit against carrying charges) represents approximately 2 years of net income for the Applicant's business;
d) Put another way, the balance is equivalent to almost 3 months of distribution revenue;
e) The balance, if written off would result in the distribution business reporting a significant net income loss; and

[2] Response to VECC interrogatory # 3 (c)
3 Page 9 of application – Manager's Summary

f) The balance is material and, as discussed below, recovery of the balance will be used to assist in financing the costs of certain major capital projects planned for 2009 and 2010.

Retroactivity

North Bay's evidence included corrections made to its RSVA balances for the period prior to December 31, 2004. Board staff's submission noted that the Board had approved North Bay's request for recovery of regulatory assets as of December 31, 2004 in its 2006 Electricity Distribution Rate (EDR) decision. Board staff submitted that the Board may wish to consider the retroactive nature of North Bay's request. Board staff submitted that in the Board's decision on Northern Ontario Wires' (NOW) 2009 EDR application, the Board had disallowed NOW's requested correction to the balances of its Account 1571 (one of its variance accounts) as of December 31, 2004. Board staff further noted that the Board decision on Lakefront Utilities Inc.'s (Lakefront) 2008 EDR application had stated that the proposed adjustment to its error on Account 1570 would result in significant retroactivity and accordingly denied the adjustment.

In its reply submission, North Bay submitted that it should be permitted to make corrections to the RSVA balances in order to ensure that the costs were properly passed through. North Bay submitted that the RSVAs track the differences between the amounts paid by North Bay to the IESO for items such as electricity, transmission services and wholesale market services and the amounts billed to its customers. Therefore, the amounts tracked in RSVAs are considered to be a pass-through to customers. North Bay further stated that both the Report of the Board on Electricity Distributors' Deferral and Variance Account Review Initiative[4] (EDDVAR Report) and the Report of the Board on Transition to International Financial Reporting Standards[5] (IFRS Report) indicated that pass-through accounts do not require a prudence review. As a result, North Bay submitted that the Board's role should be to ensure North Bay's practices had been corrected and that the corrected balances for these pass-through accounts are recovered.

North Bay further submitted that the cases cited by Board staff did not support staff's position concerning the recoveries sought in its application. The RSVA accounts for which North Bay is seeking adjustments are pass-through accounts which are ongoing

[4] Report of the Board, EB-2008-0046
[5] Report of the Board, EB-2008-0408

and will remain to be used to accrue for ongoing variances. By contrast, in North Bay's view, the cases referenced by Board staff, involve accounts that are neither pass-through nor ongoing in nature (Account 1571 for NOW and 1570 for Lakefront). As such, in North Bay's view these cases are not supportive of an "out-of-period" finding, as suggested by Board staff.

Board staff submitted that if the Board accepted the adjustment for the RSVA balances prior to 2005, this adjustment would, in effect, vary the Board's RP-2005-0020/EB-2005-0397 decision. That decision disposed of North Bay's RSVA balances as of December 31, 2004 on a final basis. Staff noted that the deadline for seeking any variance to that decision had long passed.

North Bay submitted that in the past, the Board had exercised its discretion to vary its own decision after the expiration of the 20-day period. North Bay cited the Board Decision on the Toronto Hydro-Electric System Limited third tranche Conservation and Demand Management Plan in which the Board varied its Decision one and a half years after the original Decision (RP-2004-0203/EB-2004-0485/EB-2006-0145).

Board staff also noted that if the Board decided to allow North Bay's RSVA balances to be disposed for the period January 1, 2005 to December 31, 2008 only, North Bay would refund the amount of $503,506.69 plus interest to its customers.

In its reply submission, North Bay rejected this suggestion on the basis that it would penalize North Bay for its efforts to correct its account practices and urged the Board to approve its application. North Bay submitted that the corrected balances for these pass-through accounts should be recovered.

Recovery period

In its original application, North Bay requested approval for proposed rate riders to be effective July 1, 2009 and a disposition period of three years. VECC submitted that it would be appropriate to change the effective date to November 1, 2009, which would coincide with the change in RPP rates.

In its reply submission, North Bay agreed with VECC's proposal and requested that the proposed rate riders be effective for the period November 1, 2009 to October 31, 2012.

BOARD FINDINGS

For the reasons that follow the Board denies the applicant's request to establish rate riders for the purpose of collecting revenues based on corrected RSVA account balances.

In support of its request, North Bay provided the following:

- A detailed record of the original account balances contrasted against the corrected balances to illustrate the variance that forms the basis of the relief sought as well as the chronology of events that resulted in the corrections.
- Its position regarding the significance of the corrected balances in terms of the quantum in relation to its net income and distribution revenue.
- Details on the intended use of the funds and the concomitant benefits to its customers.

North Bay also noted that due to its stable population base there is little risk of intergeneration cross subsidy.

On the issue of the correction of the account balances, the Board accepts that certain account balances submitted for the purpose of establishing the 2006 rates were incorrect. The record is clear that errors in accounting were made and that a substantial effort has been made to establish accurate balances, based on the correct accounting methodologies and entries. The applicant appears to have taken due care and effort to reform certain accounting procedures to be compliant with the Accounting Procedures Handbook.

As to the significance of the balances, North Bay contends both in its original application and in its reply submission that the money it proposes to collect by way of rate riders is to be applied to needed capital projects within the applicant's service area. At paragraph four of its reply submission North Bay states the following:

"To be clear, the money recovered is not being used to enrich the utility or its shareholder – it is being put back into the system that serves the Applicant's customers."

The Board agrees that the amount proposed to be collected is significant. However, the applicant's position on this point is not clear to the Board. The applicant submits that the

Board should consider the negative impact on the financial status of the utility and at the same time submits that the recovery sought is not to be used to enrich the utility.

These seemingly contradictory contentions may arise from the applicant's understanding, as it is characterized in the application that the corrected account balances represent monies currently owed to the utility.

While no party took issue with the intended use of the sought after money, for reasons that follow the Board will not opine on the appropriateness of the applicant's proposed spending in the context of this application.

The main area contested in the application is the issue of retroactivity. Board staff submitted that the Board may wish to consider the retroactive nature of North Bay's request and cited recent Board decisions where the Board denied requests similar to North Bay's. North Bay responded by noting that the "pass through" nature of the accounts in its application should be considered and that the balances represent its true costs.

In the normal course a utility need not concern itself with the fluctuations in RSVA account balances driven by timing differentials between the incurrence of costs and the collection of offsetting revenues. The purpose of the account is to track the variance with the intent to dispose of the balances in a manner that keeps the applicant whole. However, once the rates, including any associated riders from the clearance of the RSVAs or any other account, have been determined to be final the Board has little, if any, power to alter these rates retroactively.

The applicant has not demonstrated any financial hardship that may have been as a result of the incorrect balances being cleared. The applicant submits that the rationale for allowing the prior period adjustment is that RSVA balances are intended to be a "pass trough" and essentially immune from any retroactivity concern. The Board does not differentiate its treatment of the RSVA accounts from any other component of the approved rates in its consideration of retroactivity. The reasonable rate-payer confidence in the continuation of rates deemed final are diminished equally irrespective of the impetus of the retro-activity.

In support of its request the applicant submits that the intended use of the recovered amounts will be of benefit to the customer due to system improvements. The Board does not consider the establishment of a future need to be sufficient grounds to warrant a prior period adjustment. There are other more appropriate processes to establish the revenues required for future spending.

A central function of cost of service rate making is the matching of future revenues with anticipated reasonably incurred future costs. In a typical rate setting exercise an applicant determines what its reasonably incurred costs will be in the future period for which the applied for rate will be charged. The applicant provides its rationale for the level of spending that underpins its revenue requirement and the Board sets rates in accordance with what it considers to be just and reasonable. It is a holistic process that considers all expected revenues and all expected costs to determine the appropriate rates.

North Bay's 2006 rates were established on the basis of what was thought to be a true account of its expected future costs and revenues. The fact that for 2006 rates North Bay chose to use a historic test year as a proxy for future costs does not alter the concept that rates were established on a prospective basis to match future revenues against future reasonably incurred costs.

North Bay cited the Board's desire to maintain the use of deferral accounts in support of its claims. It is not rational to conclude that the Board's desire to maintain the use of deferral accounts suggests that the final disposition of deferral accounts is anything less than final.

The Board notes that the 2007 rate setting process was a mechanical process that continued the 2006 rates with some inflation related adjustments. The Board initiated a rate setting framework for the electricity distribution sector that provided an opportunity to distribution companies to apply for rates on a cost of service basis for the 2008 rate year or any subsequent year. North Bay did not elect to seek increases to its rates in 2008 or 2009 to cover the costs of these activities but does intend to apply for new rates for 2010 on a cost of service basis. There is no evidence that North Bay was forced to delay capital spending due to lack of revenue or any evidence as to why North Bay did not apply for a rate increase earlier if it saw a need to increase its spending.

The Board expects North Bay to establish its stated needs in the context of its overall spending in its 2010 cost of service rate application. The disposition of the account balances for the time period January 1, 2005 to December 31, 2008 would also more appropriately be done in the context of that rate setting proceeding.

As Board staff noted, a decision to allow North Bay's RSVA balances to be disposed for the period January 1, 2005 to December 31, 2008 only would result in North Bay refunding the amount of $503,506.69 plus interest to its customers.

North Bay submitted that a finding of the Board that disallowed the prior period adjustment but required North Bay to dispose of the corrected balance would penalize North Bay for its efforts to correct its account practices. The Board does not agree with North Bay's characterization. The application of sound rate setting principles results in a fair and transparent process that protects the interests of both ratepayers and the utility alike. While North Bay is to be commended for its efforts, there is a basic expectation that a licensed franchise holder will provide the Board with an accurate account of its financial affairs for rate setting purposes.

The Board is not driven by a need for a symmetrical treatment of ratepayers and utilities in situations where correction of utility mistakes is required. The utility has control of its books and records and has the responsibility to ensure mistakes do not occur. For this reason the Board could find in favour of the ratepayer in certain situations and not find in favour of the utility if the utility was in the same situation.

The Board notes that North Bay has identified spending requirements to maintain service to its customers. The Board further notes that North Bay has not considered it necessary to apply for a cost of service rate increase to provide the funds for these requirements before now. The filing of its rate application for 2010 rates provides the appropriate and timely opportunity to seek the revenues it claims are required. In this way North Bay's ratepayers will be afforded the opportunity to provide comments that are informed by North Bay's total spending plan.

North Bay's request to clear the RSVAs using corrected balances for the period prior to January 1, 2005 is therefore denied. The Board has already issued a final decision related to these balances, and it will not retroactively alter these balances. The Board also chooses to not clear the RSVA balances from January 1, 2005 forward at this time. The Board will consider the disposition of these balances either through its quarterly review of commodity deferral accounts pursuant to s. 78(6.1) of the Act, or in North Bay's next rates case. The request for the disposition of the carrying charges associated with the balances from January 1, 2009 to June 30, 2009 is therefore also denied at this time.

COST AWARDS

The Board may grant cost awards to eligible stakeholders pursuant to its power under section 30 of the Ontario Energy Board Act, 1998. When determining the amount of the cost awards, the Board will apply the principles set out in section 5 of the Board's Practice Direction on Cost Awards. The maximum hourly rates set out in the Board's Cost Awards Tariff will also be applied.

THE BOARD DIRECTS THAT:

1. VECC shall file with the Board and forward to North Bay its cost claim within 26 days from the date of this Decision.

2. North Bay shall file with the Board and forward to VECC any objections to the claimed cost within 40 days from the date of this Decision.

3. VECC shall file with the Board and forward to North Bay any responses to any objections for cost claims within 47 days of the date of this Decision.

4. North Bay shall pay the Board's costs incidental to this proceeding upon receipt of the Board's invoice.

DATED at Toronto, September 8, 2009

ONTARIO ENERGY BOARD

Original Signed By

Kirsten Walli
Board Secretary

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In the Court of Appeal of Alberta

Citation: Epcor Generation Inc. v. Alberta (Energy and Utilities Board), 2003 ABCA 374

Date: 20031222
Docket: 03-0178-AC; 02-0033-AC
Registry: Calgary

Between:

Epcor Generation Inc.

Applicant (Appellant)

- and -

Alberta Energy and Utilities Board

Respondent

Memorandum of Decision of
The Honourable Madam Justice Fruman

Application for Leave to Appeal Decisions 2001-45 and
2001-95 (as amended by 2001-115) of
The Alberta Energy and Utilities Board
and Dismissal of the Review and Variance Application
Dated May 26, 2003

Memorandum of Decision of
The Honourable Madam Justice Fruman

Introduction

[1] The applicant, EPCOR Generation Inc., seeks leave to appeal several decisions of the Alberta Energy and Utilities Board: Decisions 2001-45 and 2001-95 (as amended by 2001-115), which altered the sharing ratio between EPCOR and its customers in relation to a deferral account; and the Board's decision not to review and vary Decision 2001-95 (as amended by 2001-115).

Facts

[2] In Alberta, utilities are usually regulated using a future test year regulatory framework in which the Board approves a forecast of a utility's revenue requirements that equates to a forecast of its future costs. However, if the Board is unable to determine a just and reasonable forecast, deferral accounts may be established to deal with uncertain items. In this case, due to the inability to accurately forecast pool prices, deferral accounts were created for 1999 and 2000 pursuant to Decisions U99099 and 2000-5. The difference between the actual hourly pool prices and the forecast hourly pool prices would be calculated and recorded in the deferral accounts.

[3] The decisions included a sharing formula pursuant to which EPCOR and its customers would share the deferral account balances. The original sharing ratio in Decision U99099 contemplated the customer alone would bear any surplus or shortfall, but the ratio was changed to 50/50 on February 1, 2000, in Decision 2000-5. In making the change, the Board indicated it did not want to "inappropriately dampen the hour by hour incentives" to EPCOR, but also wanted to "safeguard against inappropriate windfall gains or losses that have little to do with generation performance" (at 8).

[4] In Decision U99099, the Board directed EPCOR to apply to the Board by April 1 in the following year in order to "collect or refund the balance in all their deferral accounts" (at 204). The Board recognized "that there will be further adjustments due to the disposition of deferral accounts" (at 12).

[5] On March 30, 2001, EPCOR applied to the Board for termination of the 2000 pool price deferral account, which contained a surplus of approximately $70 million. On April 10, 2001, the Industrial Power Consumers and Cogenerators Association of Alberta (IPCCAA) applied to have the Board review and vary Decisions U99099 and 2000-5 to change the sharing ratio from 50/50 to 98/2 in favour of the customer. It argued that retention of $35 million by EPCOR would be a windfall gain.

[6] In Decision 2001-45 the Board decided IPCCAA had met the threshold to review the sharing ratio, and indicated it would examine the ratio at the hearing initiated by EPCOR to close the 2000 deferral account. In Decision 2001-95 (as amended by 2001-115) the Board found that the test for

variation of the sharing ratio had been met. It noted that the variance between actual and forecast pool prices was expected to be small, based on information provided primarily by EPCOR. However, the difference turned out to be anything but small, and the resulting surplus of approximately $70 million represented a substantial and unforseen change in circumstances (Decision 2001-95 at 27). The Board found that the majority of the surplus was due to high pool prices, not improved performance by EPCOR, and concluded the 50/50 sharing ratio resulted in a windfall gain to EPCOR that rendered the sharing formula unjust and unreasonable (at 29). The Board decided it had to distinguish between that portion of the surplus resulting from improved performance that should flow to EPCOR's shareholders, and that portion of the surplus resulting from unanticipated higher pool prices that ought to be returned to its customers (at 28). Based on the Board's consideration of the financial information, it changed the sharing ratio from 50/50 to 80/20 in favour of the customer (at 36).

[7] On March 21, 2002, EPCOR submitted a review and variance application to the Board, seeking a review of Decision 2001-95 (as amended by 2001-115). This application was denied by the Board by letter dated May 26, 2003.

<u>Test for Leave</u>

[8] Pursuant to s. 26 of the *Alberta Energy and Utilities Board Act*, R.S.A. 2000, c. A-17, leave to appeal decisions of the Board may be granted on questions of jurisdiction or law. The proposed appeal must raise a serious arguable issue: ***Nycan Energy Corp.* v. *Energy and Utilities Board (Alta.)*** (2001), 277 A.R. 391, 2001 ABCA 31 at para. 3. In considering whether to grant leave, it may be appropriate to consider the standard of review this Court would apply, should leave to appeal be granted.

<u>Decisions 2001-45 and 2001-95 (as amended by 2001-115)</u>

[9] In seeking leave to appeal Decisions 2001-45 and 2001-95 (as amended by 2001-115), EPCOR argues the Board committed a number of errors: first, the Board erred in determining it had jurisdiction to vary the sharing ratio because this was retroactive ratemaking; second, the Board was estopped from varying the sharing ratio or alternatively, it was procedurally unfair for the Board to make the variation after the conclusion of the year 2000; third, the Board erred in failing to provide adequate reasons for its conclusion about the surplus; and fourth, it erred in disregarding or rejecting EPCOR's evidence.

[10] With respect to the first ground, EPCOR argues the Board erred in determining it had jurisdiction to vary the 50/50 sharing ratio and, by altering the ratio, engaged in retroactive ratemaking.

[11] The Board based it jurisdiction on s. 57(2)(c) of the *Electric Utilities Act,* R.S.A. 2000, c. E-5, which states:

> 57(2) Any person affected by an order approving a tariff may ask the Board to review the order
>
> [. . .]
>
> (c) if, since the date of the order, circumstances have changed in a substantial and unforseen manner that renders the continuation of the tariff unjust or unreasonable [. . .]

[12] EPCOR argues the word "continuation" indicates a tariff can only be varied on a prospective, not a retroactive, basis. The Board agrees with this interpretation and confirms that it is not permitted to engage in retroactive ratemaking. The parties also agree the Board has jurisdiction to vary interim orders, deferral accounts are usually interim rather than final orders, and distribution of deferral accounts does not constitute retroactive ratemaking. See ***Edmonton (City of)*** **v.** ***Northwestern Utilities Ltd.***, [1961] 1 S.C.R. 392; ***Coseka Resources Ltd.*** **v.** ***Saratoga Processing Co.*** (1981), 31 A.R. 541 (C.A.)., leave to appeal to S.C.C. refused, [1981] 2 S.C.R. vii.

[13] However, EPCOR argues its situation is unique and, indeed, the Board acknowledges that most orders creating deferral accounts do not establish sharing ratios. EPCOR submits that because the Board fashioned the sharing ratio in consideration of its particular costs and risks, the ratio was a final order of the Board, and the Board engaged in retroactive ratemaking in varying it. It contends that nothing more than accounting or mathematical corrections were expected at the time it applied to terminate the deferral account.

[14] The Board submits the order is not final until the deferral account is closed and the balance is paid in or disbursed. It argues the rule against retroactive ratemaking is based upon a forecast-based approach to tariff setting. Deferral accounts are not forecast-based. They are established when a cost item is not subject to reasonable forecast and consist of actual gains or losses realized during the applicable period. These gains or losses are addressed through payments into, or out of, the deferral account, as directed by the Board after the deferral period. The Board contends the order establishing the deferral account and sharing ratio is interim in nature and adjustments to either do not contravene the rule against retroactive ratemaking.

[15] EPCOR's retroactive ratemaking argument hinges on the characterization of the original order as interim or final, which in turn depends largely on the facts. EPCOR contends that because of unique factual circumstances, the sharing ratio was neither an interim order nor a standard deferral account provision, but a final order.

[16] The Board viewed the circumstances differently. In deciding to vary, the Board relied on the fact Decision U99099 contemplated Board review of the deferral account balances, and recognized that adjustments might be required as a result of that review. The Board decided the deferral accounts were therefore "left open" and "continued" within the meaning of s. 57(2)(c) of the *Electric*

Utilities Act, *supra* and, because the deferral accounts had not been reconciled or the moneys disbursed, a decision to review the sharing ratio and the ultimate collection and disbursement of funds would be prospective in nature (Decision 2001-45 at 23). These findings are within the Board's jurisdiction and expertise and, on judicial review, this Court would defer to the Board on such matters.

[17] Other facts are also important, including previous changes to the sharing ratio. EPCOR contends that to avoid retroactive ratemaking, any change to the sharing ratio had to be made during the 2000 calendar year and would only affect accruals to the deferral account on a going-forward basis, that is, after the sharing ratio was altered, but not before. However, the sharing ratio was changed on February 1, 2000, at EPCOR's request, from 100/0 in favour of the customer to 50/50. That change was retroactive to January 1, 2000, which is inconsistent with EPCOR's present position.

[18] Moreover, EPCOR's argument that changes to the sharing ratio had to be made during the 2000 calender year poses a number of practical difficulties. Deferral accounts are created in response to uncertainty, which may result from rapidly changing circumstances. In theory, significant price swings could justify variations to the sharing ratio on a daily or even hourly basis, which would be unworkable given the time and cost of hearings. While EPCOR might have some idea of the running balance in the deferral account, a customer would have to request and wait for the results of an audit, then assemble and submit an application. During the intervening time period, further changes in circumstances could make the application moot. These problems support the Board's position that the sharing ratio was an interim and not a final order, and that adjustments to the sharing ratio should be handled the same way as other adjustments to the deferral account.

[19] Given the strong factual component that underlies this ground of appeal, the inconsistency and logistical difficulties associated with EPCOR's position, and the applicable standard of review, the first ground does not meet the test for leave.

[20] With respect to the second ground, EPCOR argues the Board was estopped from varying the ratio or, alternatively, it was procedurally unfair for the Board to vary it after the year-end. The estoppel argument fails to establish a basis on which to grant leave. EPCOR concedes public estoppel may not apply. See ***Mount Sinai Hospital Center* v. *Quebec (Minister of Health and Social Services)***, [2001] 2 S.C.R. 281. Private estoppel depends on a proper factual foundation, including a promise intended to be acted upon and detrimental reliance. Estoppel of any kind was not raised before the Board, evidence was not led to address these factors and the Board did not make fact findings about them. An application for judicial review is not the appropriate forum in which to raise this issue.

[21] Nor can it be said that it was procedurally unfair for the hearing to be held after the year 2000. The status of the deferral accounts could only be properly assessed when all the accrued amounts had been calculated, which could only occur after year-end. EPCOR applied for termination

of the accounts, the variation application was heard at the same time, and EPCOR participated fully in the proceedings. Accordingly, the second ground also fails.

[22] The third ground, that the Board did not provide adequate reasons, does not raise a serious arguable legal issue.

[23] EPCOR's submission that the Board erred in disregarding or rejecting evidence raises issues of fact, not law or jurisdiction. The Board is free to accept or reject evidence presented by the parties and, as an expert tribunal, it is entitled to use its expertise to arrive at different conclusions than the parties. Indeed, the highly technical nature of the disputed evidence demonstrates why evaluation of such evidence properly falls within the Board's purview.

[24] EPCOR argues the Board's rejection of evidence is patently unreasonable and amounts to a jurisdictional error or an error of law: ***Blanchard* v. *Control Data Canada Ltd.***, [1984] 2 S.C.R. 476. However, this standard is very difficult to meet and will only be satisfied when the evidence is incapable of supporting the tribunal's findings: ***Canadian Union of Public Employees, Local 301* v. *Montreal (City)***, [1997] 1 S.C.R. 793.

[25] Here the Board rejected EPCOR's submission that the increased surplus was entirely attributable to improved performance, and therefore did not accept EPCOR's calculations. The Board had the raw data before it. It identified the components of the increased surplus that reflected improved performance and those that reflected windfall, then used its expertise to calculate each of them. While EPCOR may disagree with the results, it cannot be said that the evidence was incapable of supporting the Board's conclusions. Nor can it be said that it was procedurally unfair for the Board to proceed in this fashion.

[26] Accordingly, leave to appeal Decisions 2001-45 and 2001-95 (as amended by 2001-115) is dismissed.

Review and Variance Application

[27] EPCOR seeks leave to appeal the Board's decision not to review and vary Decision 2001-95 (as amended by 2001-115). Pursuant to s. 57(2)(d) of the *Electric Utilities Act*, a person may ask the Board to review an order if, in the Board's opinion, the order contains an error of law or fact. Section 46(5)(i) of the *Alberta Energy and Utilities Board Rules of Practice*, Alta. Reg. 101/2001, provides that a review application is to be dismissed if an applicant fails to raise a substantial doubt as to the correctness of the Board's order when an error of law, jurisdiction or fact is alleged.

[28] EPCOR argues the Board misapprehended the test for review. The Board dismissed the review application and referred to EPCOR's failure to "raise a substantial issue as to [an] error of law or jurisdiction." EPCOR points out that this wording omits an error of fact, which is part of the statutory test.

[29] The evidence and argument submitted by EPCOR in the review application were fact-based and technical. In its decision, the Board noted EPCOR "failed to bring any evidence or argument which shows that these decisions were wrong or contrary to the evidence." This indicates that although the Board may have misstated the test for review, it applied the test correctly.

[30] The Board found no basis for further review. Because the test for variation in s. 57(2)(d) of the *Electric Utilities Act* invokes the Board's discretion, its conclusions on matters within its jurisdiction and expertise would attract considerable deference on appeal. Here, the major challenge was EPCOR's disagreement with the Board's allocation and calculation of the surplus, which fits comfortably within the Board's jurisdiction and expertise. No question that meets the test for leave has been demonstrated.

[31] EPCOR also complains about the adequacy of the Board's reasons and its dismissal of EPCOR's evidence. These grounds do not meet the test for leave to appeal.

[32] The applications are therefore dismissed.

Appeal heard on December 12, 2003

Reasons filed at Calgary, Alberta
this 22nd day of December, 2003

Fruman J.A.

Appearances:

F.R. Foran, Q.C.
C. Hustwick
for the Applicant (Appellant)

J.R. McKee
A.E. Domes
for the Respondent

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Alberta Utilities Commission

1915 100 YEARS of service to Alberta 2015

Milner Power Inc.

Complaints regarding the ISO Transmission Loss Factor Rule and Loss Factor Methodology

ATCO Power Ltd.

Complaint regarding the ISO Transmission Loss Factor Rule and Loss Factor Methodology

Phase 2 Module A

January 20, 2015

Alberta Utilities Commission

Decision 790-D02-2015: Milner Power Inc.
Complaints regarding the ISO Transmission Loss Factor Rule and Loss Factor Methodology
ATCO Power Ltd.
Complaint regarding the ISO Transmission Loss Factor Rule and Loss Factor Methodology
Applications 1606494, 1608563 and 1608709
Proceeding 790

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Alberta Utilities Commission
Calgary, Alberta

Milner Power Inc.
Complaints regarding ISO Transmission Loss Factor Rule and Loss Factor Methodology
ATCO Power Ltd.
Complaint regarding ISO Transmission Loss Factor Rule and Loss Factor Methodology

Decision 790-D02-2015
Applications 1606494, 1608563 and 1608709
Proceeding 790

1 Introduction and summary

1. This decision is a follow-up to a decision made by the Alberta Utilities Commission (AUC or the Commission) to uphold a complaint made by Milner Power Inc. (Milner) on August 17, 2005, about the Independent System Operator (ISO) rule 9.2: *Transmission Loss Factors* and Appendix 7: *Transmission Loss Factor Methodology and Assumptions* (collectively the Line Loss Rule) that was implemented by the Alberta Electric System Operator (AESO) on January 1, 2006. References to the Line Loss Rule should be read as the 2005 Line Loss Rule as adjusted from time to time during the period from January 1, 2006 to the present.

2. The Commission found in Decision 2012-104: *Complaint by Milner Power Inc. Regarding the ISO Transmission Loss Factor Rule and Loss Factor Methodology* that the Line Loss Rule did not comply with the relevant provisions of the *Transmission Regulation* Alberta Regulation 174/2004 (2004 *Transmission Regulation*) and the 2003 *Electric Utilities Act* S.A. 2003, c E-5.1 (2003 *Electric Utilities Act*). Upon application, the Commission granted a review of that decision and on April 16, 2014, in Decision 2014-110: *Applications for review of AUC Decision 2012-104: Complaint by Milner Power Inc. Regarding the ISO Transmission Loss Factor Rule and Loss Factor Methodology*, following a hearing, the Commission confirmed the principal findings of Decision 2012-104 that the rule was unjust, unreasonable, unduly preferential, arbitrarily and unjustly discriminatory and inconsistent with and in contravention of the 2003 *Electric Utilities Act* and the relevant portions of the 2004 *Transmission Regulation* dealing with line losses.

3. In particular, the Commission, in Decision 2014-110 found:

> The review panel has considered carefully the evidence regarding how the 2005 Line Loss Rule operates and finds that it does not comply with Section 19(1)(a) and Section 19(2)(d) of the 2004 *Transmission Regulation* and Section 25(6)(b) of the 2003 *Electric Utilities Act*.[1]
> …
> To summarize, for the reasons given in this decision, the review panel concurs with the hearing panel's finding that the AESO's MLF/2 line loss methodology does not comply with sections 19(1)(a) and 19(2)(d) of the 2004 *Transmission*

[1] AUC Decision 2014-110, April 16, 2014, page 36, paragraph 112.

> *Regulation* because the AESO's 2005 Line Loss Rule fails to assign to each generating unit a line loss charge or credit (i) based on each generating unit's contribution to transmission line losses and (ii) that is representative of each generating unit's impact on average system losses relative to load. As the majority stated in Decision 2012-104, the MLF/2 methodology is unjust because it disadvantages loss savers and does not properly charge loss creators for their losses. It is also "unjustly discriminatory as it violates all the principles of rate design that would normally be observed in a regular rate or tariff proceeding.[2]

4. On August 8, 2014, the Commission, after canvassing the parties, determined that it would proceed to hear Phase 2 of the original proceeding 790 in three modules. This proceeding deals with Module A, which was described as follows by the Commission:

> **Module A,** which will encompass the 2012 complaints from Milner and ATCO as well as Phase 2 of the original 2005 Milner complaint, will address several issues of fact and law, including:
>
> A. Whether the line loss rule, as it was from January 1, 2006 to the present, is a tariff, a rate, a charge, or something else. Whether a line loss factor produced by the line loss rule is a tariff, a rate, a charge, or something else. The legal significance of interpreting the line loss rule and/or the line loss factor as such.
> B. Whether or not Milner's 2005 complaint continued post-2008 and, if so, for how long.
> C. Compliance of the line loss rule, as it was from January 1, 2009 to the present, with applicable legislation and regulations.
> D. The Commission's jurisdiction to change or replace an ISO rule that was in effect:
>   i) from January 1, 2006 to December 31, 2008;
>   ii) from January 1, 2009 to June 11, 2012;
>   iii) from June 12, 2012 forward.
> E. The Commission's jurisdiction to change the charges and credits for transmission line losses in an ISO tariff that was in effect:
>   i) from January 1, 2006 to December 31, 2008;
>   ii) from January 1, 2009 to June 11, 2012;
>   iii) from June 12, 2012 forward.
> F. The Commission's jurisdiction to order any form of financial compensation, including to whom and from whom such compensation might be paid, for the period:
>   i) from January 1, 2006 to December 31, 2008;
>   ii) from January 1, 2009 to June 11, 2012;
>   iii) from June 12, 2012 forward.
> G. Any other matters or issues of fact and law related to those identified above that parties may wish to raise.[3]

5. The issues set out by the Commission reflected the broad sweep of issues and time frames relevant to Module A that had been raised by the parties throughout the life of the Commission's and the courts' considerations of Milner's complaint and the handling of that complaint by the Board. After considering the materials filed, the Commission has determined

[2] AUC Decision 2014-110, April 16, 2014, page 38, paragraph 121.
[3] Exhibit 524.01, AUC letter re issues list and schedule for phase 2, August 8, 2014, page 2, paragraph 6.

that it is not necessary to address each of the questions posed by it in the form those questions were asked.

6. Although most of the submissions in this proceeding have focussed on the Commission's remedial powers dealing with ISO rules, the underlying concern originally raised by Milner, when it filed its complaint in the AESO's 2005-2006 General Tariff Application proceeding, is the monetary impact on Milner of the unlawful charges and credits included in the ISO tariff. This same concern with monetary impacts can be seen in the submissions of all parties in this proceeding. Their concerns arise from the nature of the Line Loss Rule, through which any increase in the ISO tariff line loss charges to one generator will result in decreases in charges to others so as to ensure the collection of only the amounts needed to cover the actual total line loss costs in a year. This was referred to by parties as a "zero sum game." Parties are concerned that if they received credits or paid too little through the line loss components of the ISO tariff at any time in the past, they might be required to make up that underpayment and parties who may have paid too much are seeking to be reimbursed for the amount of the overpayments they made in the past. Therefore, having regard to the way in which the Line Loss Rule operates, the way in which the questions asked in sections D, E and F of the Commission's August 8, 2014 letter were addressed by the parties, and the way the Commission has interpreted the rulemaking and ratemaking provisions of the applicable legislation in this decision, the Commission has framed the issue as follows: The principal issue to be determined is whether the Commission may order a remedy or relief to correct for the payment or receipt of unlawful line loss charges and credits included in the ISO tariff on account of any period for which the Commission finds that the Line Loss Rule has been non-compliant.

7. Throughout this decision, distinctions are made between the provisions of the 2003 *Electric Utilities Act* and the 2007 amendments to the 2003 *Electric Utilities Act*. The 2003 Act will be referred to as the 2003 *Electric Utilities Act* and the Act incorporating the 2007 amendments will be referred to as the 2003/07 *Electric Utilities Act*. Where the Commission makes reference to the *Electric Utilities Act* without specifying whether it is the 2003 or 2003/07 *Electric Utilities Act*, it does so because there is no material difference between the two Acts relevant to the discussion. When the Commission discusses provisions of the 2003 *Electric Utilities Act* it refers to the powers of the Board under that Act and when it discusses provisions of the 2003/07 *Electric Utilities Act* it refers to powers of the Commission. Both versions of the *Electric Utilities Act* are discussed in the present tense.

8. The following summarizes the Commission's findings:

- The non-compliant provisions of the 2005 Line Loss Rule remain in effect today and have remained in effect and non-compliant with the *Electric Utilities Act* and the *Transmission Regulation* uninterrupted since January 1, 2006.

- Milner's complaint has continued uninterrupted from the date of its filing on August 17, 2005 and continues to the present.

- The Commission in Decision 2014-110 found that Milner's complaint satisfied the statutory requirements for the Commission to grant relief under Section 25(6) of the 2003 *Electric Utilities Act* for the period from 2006 through 2008. The Commission finds in this decision that Milner's complaint against the Line Loss Rule under the 2003 *Electric Utilities Act* would also satisfy the statutory requirements for the Commission to grant relief from January 1, 2009 to the present under either the 2003 *Electric Utilities Act* or 2003/07 *Electric Utilities Act,* whichever applies.

- The 2003 *Electric Utilities Act* and the remedies available under it apply to the Milner complaint from the date it was filed to the present.

- To complain about the Line Loss Rule is to complain about the line loss charge components of the ISO tariff. The line loss charge components of the ISO tariff have been unjust, unreasonable, unduly preferential, and arbitrarily or unjustly discriminatory and inconsistent with Alberta legislation since January 1, 2006 because they are produced by the Line Loss Rule that has been unjust, unreasonable, unduly preferential, and arbitrarily or unjustly discriminatory and inconsistent with or in contravention of the *Electric Utilities Act* and the *Transmission Regulation* since January 1, 2006.

- The Line Loss Rule and the line loss components of the ISO tariff are subject to a negative disallowance scheme.

- Because the Line Loss Rule and the line loss charge components of the ISO tariff are subject to a negative disallowance scheme, they were automatically effectively interim and have remained effectively interim since they went into effect on January 1, 2006.

- It is not impermissible retroactive ratemaking for the Commission to grant a tariff-based remedy to correct for the payment or receipt of unlawful line loss charges and credits included in the ISO tariff from the date that the unlawful Line Loss Rule went into effect on January 1, 2006.

- The Commission may grant a tariff-based remedy or relief under either the 2003 *Electric Utilities Act* or, if it were to apply, the 2003/07 *Electric Utilities Act*.

2 Chronology

9. The origin of this proceeding extends back to August 17, 2005, when Milner filed a complaint with the Commission's predecessor, the Alberta Energy and Utilities Board (EUB or the Board).[4] Milner's complaint was about the Line Loss Rule, which was due to take effect on January 1. 2006. This ISO rule was made pursuant to the 2004 *Transmission Regulation* and approved by the AESO's Executive Rules Committee in May 2005. Section 19 of this regulation prescribed new criteria for the determination of line loss factors assigned to generating units through ISO rule-making in place of the previous regime of line loss factors established through ISO tariff approval proceedings before the Board.[5]

10. Milner's complaint was filed pursuant to Section 25 of the 2003 *Electric Utilities Act* concerning the ISO Line Loss Rule and pursuant to Section 26 of the 2003 *Electric Utilities Act*

[4] Exhibit 2.01, Milner, Complaint Application, August 17, 2005.
[5] Exhibit 533.02, AESO Line Loss Rule Consultation Record, September 5, 2014, pdf page 17.

concerning certain conduct of the AESO in failing to comply with Board directives and in implementing the Line Loss Rule. Milner's complaint sought the following relief under Section 25(6) of the 2003 *Electric Utilities Act*:

(a) Directing that the present complaint be set down for hearing in accordance with subsection 25(6) of the EUA and section 22 of the Rules of Practice;

(b) Directing the AESO to comply with all outstanding Board directives concerning the implementation of the AESO's loss factor methodology in accordance with subsection 8(1)(d) of the Transmission Regulation, AR 174/2004 (the "Regulation") and Board Decisions 2000-1, 2000-27, 2002-064 and 2002-104;

(c) Revoking or suspending the Rule in accordance with subsection 25(6)(b) of the EUA until the AESO complies with the Board's outstanding directives and until the Rule is replaced by a loss factor methodology which complies with the Regulation;

(d) Directing that the AESO replace its marginal loss factor methodology as set out in the Rule with an "average MW in" methodology or other loss factor methodology as approved by the Board in accordance with subsection 25(6)(b) of the EUA;

(e) Directing in accordance with subsection 25(6)(b) of the EUA that any loss factor methodology approved by the Board be phased in, so as to limit the variation in loss factors that any generator sees year to year to no more than one half of the average system losses as a percentage of total MW supplied;

(f) Directing that the AESO remove transmission must run ("TMR") MW dispatches from the AESO's Generic Stacking Order ("GSO") for the purposes of establishing loss factors, in compliance with subsection 1(1)(a) of the Regulation and pursuant to subsection 25(6)(b) of the EUA;

(g) Extending the AESO's present tariff based loss factor methodology from December 31, 2005, on a final basis, as necessary, in accordance with subsection 10(2) of the Alberta Energy and Utilities Board Act, RSA 2000, c. A-19.5 (the "AEUBA") and subsection 124(1)(a) of the EUA, until replaced as requested herein or as otherwise replaced or amended as directed by the Board;

(h) Where it appears to the Board to be just and proper, granting partial, further or other relief in addition to, or in substitution for that applied for, as fully and in all respects as if the present application had been for that partial, further or other relief, in accordance with subsection 10(3)(f) of the AEUBA.[6]

11. Section 25(6) of the 2003 *Electric Utilities Act* provided that the Board may order the ISO to revoke or change a provision of an ISO rule that, in the Board's opinion, is unjust, unreasonable, unduly preferential, arbitrarily or unjustly discriminatory or inconsistent with or in contravention of the 2003 *Electric Utilities Act* or the regulations.[7]

12. The ground for Milner's complaint relevant to this proceeding was that the Line Loss Rule did not comply with sections 19(1)(a) and 19(2)(d) of the 2004 *Transmission Regulation.*[8]

13. On August 17, 2005, Milner also filed its ISO rule complaint in the then pending AESO 2005/2006 General Tariff Application (GTA) proceeding. Milner sought to intervene in that

6 Exhibit 2.1, Milner, Complaint Application, August 17, 2005, pages 2 and 3.
7 Exhibit 2.1, Milner, Complaint Application, August 17, 2005, pages 1 and 2.
8 Exhibit 2.1, Milner, Complaint Application, August 17, 2005, page 3.

tariff proceeding to have the Board consider its Line Loss Rule complaint that the line loss charges under the tariff were contrary to the 2004 *Transmission Regulation*, and were unjust, unreasonable, unduly preferential, and arbitrarily or unjustly discriminatory.[9] The full text of Milner's August 17, 2005 complaint is attached as Appendix 5.

14. On August 28, 2005, the Board issued tariff Decision 2005-096: *Alberta Electric System Operator (AESO) 2005/2006 General Tariff Application*. Milner's application seeking consideration of its complaint in the AESO 2005/2006 GTA was not dealt with in the decision. Rather, the Board's ruling was addressed in the cover letter to Decision 2005-096. The Board stated:

> The Board acknowledges the receipt of a complaint from Milner Power (Milner) with respect to the AESO Rule regarding the development of loss factors to be effective January 1, 2006. In the complaint, on file with the Board as Application 1414213, Milner requested that the Board not relieve the AESO of its obligation to respond to certain directives from prior Board decisions. The Board notes that the date for submission of evidence in the GTA is well past. The Board is therefore not willing to consider the presentations of Milner within the context of the GTA Application.
>
> This determination is made, however, without prejudice to Milner's right to pursue its complaint pursuant to Section 25 of the *Electric Utilities Act* (the EUA or the Act). The Board is continuing to review Application 1414213 and will issue notice in due course with respect to the process to be followed.[10]

15. On November 24, 2005, Milner filed an application with the Board for review and variance of Decision 2005-096. [11]

16. On December 30, 2005, the Board issued EUB Decision 2005-150: *Complaint Against the Proposed AESO Line Loss Rule* in which it summarily dismissed Milner's complaint. This decision also included a statement that the AESO was free to implement its Line Loss Rule effective January 1, 2006.

17. The first ISO tariff to include line loss charges based on the Line Loss Rule came into effect on January 1, 2006.[12]

18. On January 26, 2006, Milner applied to the Alberta Court of Appeal for leave to appeal Decision 2005-150 on five separate grounds.

19. On March 28, 2006, Milner applied to the Alberta Court of Queen's Bench seeking judicial review of Decision 2005-150 and also to compel the Board to include in the review record a November 28, 2005 Alberta Department of Energy "Role and Mandate Refinements for Alberta Electric Industry Implementing Agencies" policy paper. This application alleged apprehension of bias and lack of independence on the part of the Board panel deciding Decision 2005-150 and that it had improperly fettered its discretion by improperly considering and

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9 Exhibit 559.01, Milner Reply Argument, October 22, 2014, page 26, paragraph 112.
10 AUC Proceeding 14250, Board Letter Aug 28, 05 – Cover Letter for Decision 2005-096, August 28, 2005.
11 AUC Proceeding 14250, Review and variance application of Decision 2005-096, November 24, 2005.
12 AUC Decision 2005-096, August 28, 2005, page 1.

acceding to directives in this policy paper to defer to the AESO in matters said to be within the AESO's statutory mandate such as the Line Loss Rule.

20. On April 5, 2006 Milner's application seeking review and variance of Decision 2005-096 was denied by the Board.[13] Milner sought leave to appeal this decision to the Alberta Court of Appeal on two grounds.

21. On June 13, 2006, Milner's application to the Alberta Court of Queen's Bench seeking judicial review of Decision 2005-150 was heard.

22. On August 18, 2006, the application seeking judicial review was dismissed.[14] Milner appealed this dismissal to the Alberta Court of Appeal.

23. On April 11, 2007, the new *Transmission Regulation*, Alberta Regulation 86/2007(2007 *Transmission Regulation)* came into force. Sections 19(1)(a) and 19(2)(d) did not change (although they were renumbered as Sections 31(1)(a) and 31(2)(d), respectively), nor did the AESO change the marginal loss factor divided by two (MLF/2) methodology used to calculate transmission line loss factors under the ISO Line Loss Rule. Rather, the 2007 *Transmission Regulation* only changed the limits (collars) placed on line loss factors used to determine the charges and credits in the ISO tariff. The AESO updated the Line Loss Rule to comply with the change in the collars. However, the AESO did not file the Line Loss Rule containing the new collars with the Commission as an ISO rule pursuant to Section 20.2(1) of the 2003/07 *Electric Utilities Act*.[15] The effective date of the changes to the Line Loss Rule was January 1, 2009.

24. On April 20, 2007, the 2003 *Electric Utilities Act* was amended. Several new provisions came into force on January 1, 2008. One of the amendments was the repeal of Section 25 of the 2003 *Electric Utilities Act.* It contained the grounds for relief then specified in Section 25(6) where a complaint about an ISO rule had been made. New provisions dealing with objections to ISO rules before they come into effect were added to the Act as were new complaint provisions in a new Section 25 which, among other things, deals with complaints against ISO rules that are in effect. New grounds for complaints against ISO rules in effect and objections to ISO rules not yet in effect were substituted for the previous grounds applicable to complaints.[16] Some transitional provisions from the 2003 *Electric Utilities Act* to the 2003/07 *Electric Utilities Act* were also added.

25. On August 21, 2007, the Alberta Court of Appeal dismissed Milner's appeal of the dismissal of its application seeking judicial review of Decision 2005-150 while allowing further consideration by it of Milner's application for further document disclosure following determination of Milner's two applications seeking leave to appeal which was then still pending.[17]

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[13] AUC Proceeding 14250, Denial letter of review and variance decision of 2005-096, April 5, 2006.

[14] 2006 ABQB 537.

[15] There appears to have been no requirement for the AESO to file this under section 20.2(1) of the 2003/07 *Electric Utilities Act* because of the transition provisions in Section 20.1 of that Act.

[16] For objections before a rule goes into effect, 2003/07 *Electric Utilities Act* Section 20.4(1)(a)(b)(c)(d) and for complaints about an ISO rule already in effect Section 25(1)(b)(i)(ii)(iii).

[17] *Milner Power Inc.* v. *Alberta (Energy and Utilities Board),* 2007 ABCA 265.

26. On November 7, 2008, the Board filed with the Alberta Court of Appeal the record of proceedings required for the court's determination of Milner's applications seeking leave to appeal. In April and May 2009, the filing of memoranda of counsel regarding the leave to appeal applications followed.

27. On September 21, 2009, Milner was granted leave to appeal EUB Decision 2005-150 but was not granted leave to appeal the Board's denial of review and variance, which confirmed Decision 2005-096."[18]

28. On July 29, 2010, in *Milner Power Inc.* v. *Alberta (Energy and Utilities Board),* 2010 ABCA 236 (*Milner*), the Court of Appeal of Alberta allowed Milner's appeal of the dismissal of its complaint against the ISO Line Loss Rule under Section 25 of the *Electric Utilities Act*. The court held that "[t]he Board's Decision 2005-150 is vacated and the matter is remitted to the Board to continue to further investigate or hold a hearing to determine whether there was a contravention of section 19 as alleged."[19]

2.1 Proceeding 790 and Decision 2012-104

29. On September 20, 2010, the Commission issued a notice of proceeding designated as Proceeding 790.[20] In a letter dated February 28, 2011, the Commission bifurcated Proceeding 790 into two phases: the first phase to consider whether the 2005 Line Loss Rule contravened Section 19 of the 2004 *Transmission Regulation* and the second phase to determine the relief that might be granted should the complaint be upheld.[21]

30. The oral hearing respecting the first phase of Proceeding 790 was conducted from October 19 to October 22, 2011, and was followed by written argument. Decisions 2012-104 and 2012-105: *Complaint by Milner Power Inc. Regarding the ISO Transmission Loss Factor Rule and Loss Factor Methodology – Transmission Must Run*[22] were issued by the Commission on April 16, 2012. In Decision 2012-104, the majority of the hearing panel determined that the complaint by Milner was valid and that the Commission would move to the next phase of the proceeding.[23]

2.2 Proceeding 1945 and Decision 2013-159

31. In June 2012, the Commission received four applications seeking review and variance of Commission Decision 2012-104, filed by the AESO, Capital Power Corporation (Capital Power), TransAlta Corporation (TransAlta) and TransCanada Energy Ltd. (TransCanada). The preliminary phase of these review and variance applications was designated as Proceeding 1945.

32. On June 11, 2012, Milner filed a second complaint with the Commission regarding changes to the Line Loss Rule that took effect on January 1, 2009. Milner requested that its original complaint filed on August 17, 2005 also apply with equal effect to any revisions of the

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18 *Milner Power Inc.* v. *Alberta (Energy and Utilities Board),* 2009 ABCA 305.
19 *Milner*, paragraph 61.
20 Exhibit 64.01, AUC Notice of Proceeding, September 20, 2010.
21 Exhibit 110.01, AUC Ruling re Bifurcation, February 28, 2011.
22 The use of transmission must run generation when calculating loss factors was an issue in Proceeding 790. The Commission issued Decision 2012-105 regarding this issue, which the Commission considered is a separate issue from the methodology used to calculate loss factors.
23 AUC Decision 2012-104, April 16, 2012, page 33, paragraph 167.

Line Loss Rule beyond January 1, 2009. On July 30, 2012, ATCO Power Ltd. (ATCO Power) filed a similar ISO rule complaint.[24]

33. Effective October 10, 2012, the AESO filed ISO rules Section 501.10 with the Commission and removed ISO rule 9.2 as part of the AESO's Transition of Authoritative Documents Project. These changes were filed by the AESO on an expedited basis under Section 20.6 of the 2003/07 *Electric Utilities Act* in Application 1608876. The AESO's October 2, 2012 Notice of Filing respecting this rule stated that the changes were not intended to circumvent or dismiss the complaints submitted by Milner and ATCO Power against ISO rule 9.2. The AESO further stated that it wished to preserve the complaints by Milner and ATCO Power and requested the Commission to transfer the complaints to ISO Rules Section 501.10 upon removal of existing ISO rule 9.2.[25]

34. On April 23, 2013, the Commission issued Decision 2013-159: *Decision on Preliminary Phase of Request for Review and Variance of AUC Decision 2012-104: Complaint by Milner Power Inc. regarding the ISO Transmission Loss Factor Rule and Loss Factor Methodology* (AUC Decision 2013-159) and granted a second stage consideration of review and variance of Decision 2012-104.[26] The resulting proceeding was designated as Proceeding 2581.[27]

2.3 Proceeding 2581 and Decision 2014-110

35. The Commission reviewed Decision 2012-104 in an oral hearing held from October 7 through October 18, 2013. Written argument followed.

36. On April 16, 2014, the Commission issued Decision 2014-110. It denied variance of Decision 2012-104 in any respect now relevant to Module A of this proceeding and found that the Line Loss Rule did not comply with the 2004 *Transmission Regulation* and was unjust, unreasonable, unduly preferential, arbitrarily or unjustly discriminatory and inconsistent with or in contravention of the 2003 *Electric Utilities Act*. The Commission then indicated it would proceed with the second phase of its consideration of Milner's complaint to determine the relief or remedy to be given.[28]

2.4 Current Proceeding 790, Phase 2, Module A

37. On April 24, 2014, the Commission established a schedule to receive submissions from parties regarding the relief or remedy that may be available in this proceeding.[29] In June 2014, the Commission received submissions from Milner, ATCO Power, Capital Power, TransAlta, TransCanada, the AESO, ENMAX Energy Corporation (ENMAX) and AltaGas Ltd. (AltaGas) regarding Phase 2 of this proceeding.

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24 The Milner and ATCO Power complaints from 2012 are filed as Application 1608563 and 1608709, respectively.

25 Exhibit 533.02, AESO Line Loss Consultation, September 5, 2014, pdf page 959.

26 AUC Decision 2013-159, April 23, 2013, page 16, paragraph 57.

27 Due to limitations in its electronic filing system, in order to initiate the second phase of the variance application the Commission created four new applications on May 3, 2013 relating to the review applicants: 1609554-1 – Capital Power, 1609555-1 – TransCanada, 1609556-1 – TransAlta, 1609557-1 – AESO.

28 AUC Decision 2014-110, April 16, 2014, paragraphs 147-148, page 44.

29 Exhibit 312.01, AUC Letter polling parties re Phase 2, April 24, 2014.

38. On July 4, 2014, the Commission issued a notice of proceeding for Phase 2 consideration of relief and remedy in this proceeding. In the notice, the Commission requested a statement of intent to participate by July 25, 2014 from any party that was not registered in this proceeding, or Proceeding 1945 or Proceeding 2581.[30] The Commission received one additional statement of intention to participate from Powerex Corp. (Powerex).

39. On August 8, 2014, the Commission released an issues list and proceeding schedule directing that Phase 2 of this proceeding be divided into three modules, two of which would run concurrently, and the last of which would proceed only if required, based on the outcome of the first two modules. The Commission directed that Module A encompass the 2012 complaints from Milner and ATCO Power[31] as well as Phase 2 of the original 2005 Milner complaint while addressing several issues of fact and law as specified in the Commission's letter.[32]

40. Module B was directed to address the development of a new line loss factor calculation methodology and line loss rule that meet the legislative requirements. On May 23, 2014, the AESO submitted that it anticipated it could design a methodology consistent with the findings in the Commission's decisions and the legislation.[33] In a subsequent submission on June 6, 2014, the AESO stated that it expected to be able to file its proposed new methodology within four months.[34] In a letter dated August 8, 2014, the Commission directed the AESO to file its proposed new rule and methodology in this proceeding by no later than December 4, 2014. It also invited submissions from all parties as to what order(s) the Commission should issue to the AESO pursuant to the *Electric Utilities Act* in relation to the proposed new rule.

41. Module C was directed to address determination of any financial compensation and the parties entitled to receive or required to pay monetary compensation. The Commission also indicated that Module C would be held only if required following the determinations made in Modules A and B. The Commission set a schedule of September 24, 2014 for written argument from all parties regarding issues identified for consideration in Module A of Phase 2 of this proceeding and what order(s) the Commission should issue to the AESO with respect to changes in the ISO Line Loss Rule, with reply from all parties due October 22, 2014.

42. The Commission considers that the record for Module A of Phase 2 of this proceeding closed on October 22, 2014.

3 Positions of the parties

43. The parties filed initial submissions and reply arguments regarding their respective positions on the issues to be addressed in Module A in Phase 2 of this proceeding. The Commission has carefully considered each of the submissions made in this proceeding. In this decision, the Commission does not adopt the approach often followed in other Commission decisions where it reiterates the arguments made by each party.

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30 Exhibit 521.01, AUC Notice of Proceeding, July 4, 2014.
31 Applications 1608563-1 and 1608709-1, respectively.
32 Exhibit 524.01, AUC Letter re issues list and schedule, August 8, 2014.
33 Exhibit 506.01, AESO process submission, May 23, 2014, page 4.
34 Exhibit 518.01, AESO process reply submission, June 6, 2014, page 1.

44. As noted above, the principal point of contention among the parties is whether the Commission may order a remedy or relief to correct for the payment or receipt of unlawful line loss charges and credits included in the ISO tariff on account of any period for which the Commission finds that the Line Loss Rule has been non-compliant. The parties and their arguments can be grouped conveniently into those that support the Milner application and assert that the Commission may order relief and those that oppose the Milner application and argue that the Commission has no remedial authority with respect to past line loss charges and credits that were unlawful. However, while the conclusions of parties within each group may have been similar or consistent, the approaches taken by those parties are often quite different and engage or focus on different provisions in the legislation and different case law or the same case law for different purposes. In order to assist readers in understanding the Commission's discussion and findings that follow, a highly condensed summary of the submissions made by various parties is provided below. This summary is not intended to be exhaustive. The Commission's findings in this proceeding are informed by the full text of the submissions filed and are not premised on the following summary. The full written submissions of each party are readily available on the record of this proceeding. The Commission has also undertaken a full review of the legislative instruments and case law to assist in its decision making.

45. Milner, ATCO Power and Powerex (the claimants) generally advocate a similar position. That is, the Commission's finding that the Line Loss Rule contravenes the 2003 *Electric Utilities Act* and the 2004 *Transmission Regulation* means that the line loss charges in the ISO tariff equally offend the governing legislation and regulations now in effect. The claimants emphasize that as the Commission's core statutory mandate and duty is to ensure that rates are just and reasonable, the Commission, of necessity, has the legislative authority under the 2003 *Electric Utilities Act* and, to the extent applicable to the circumstances of this proceeding, under the 2003/07 *Electric Utilities Act* as well, to order a tariff-based remedy for the excessive line loss charges line loss savers were required to pay from 2006 onward. They contend that it is incumbent upon the Commission to arrive at this determination because it is the only just and reasonable outcome.[35]

46. The claimants' position is contested by the AESO, Capital Power, TransCanada, TransAlta, Enmax and AltaGas (the respondents). While some of the respondents acknowledge that the provisions of the 2003 *Electric Utilities Act* may apply to the period from January 1, 2006 to the end of 2007,[36] all respondents contend that the Commission's legislative authority over ISO rules from 2008 onward is governed exclusively by the 2003/07 *Electric Utilities Act*, and that the Commission's remedial power to change the Line Loss Rule under Section 25 of that Act is strictly limited to directing the AESO to do so prospectively. Some respondents argue that the applicable law not only precludes the Commission from retroactively changing the Line Loss Rule but that it also prevents the Commission from retroactively changing the associated line loss charges in the ISO tariff. The remaining respondents argue that while the Line Loss Rule can only be changed prospectively (as a result of the operation of Section 25(9)), the line loss charge components of the ISO tariff can be altered retroactively where those line loss charges and credits have been made interim by the Commission. All respondents, however, contend that

[35] Exhibit 549.01, Milner Argument, September 24, 2014, page 25, paragraph 106; exhibit 548.01, ATCO Power Argument, September 24, 2014, pages 27 and 28, paragraphs 101 to 103; and exhibit 541.01, Powerex Argument, September 24, 2014, page 9, paragraph 33.

[36] Exhibit 544.02, AltaGas Argument, September 24, 2014, pages 12 and 13, paragraph 27; and exhibit 547.01, AESO Argument, September 24, 2014, page 6.

it is neither unjust nor unreasonable that the Commission is bound by the limitations imposed by applicable law.[37]

47. The claimants argue that the Line Loss Rule, having been found to be unlawful for the period 2006-2008, should also be found to be unlawful to the present day, and that the provisions of the ISO tariff relating to line loss charges should likewise be found to be unlawful from January 1, 2006 to the present day. They also say that the Line Loss Rule never changed with respect to the MLF/2 methodology that was responsible for the rule being non-compliant between 2006 and 2008 and that this unlawful methodology remained an integral part of the rule from January 1, 2009 to the present. As a result, the claimants contend that Milner's complaint continues to apply with equal effect to the unlawful Line Loss Rule and the associated line loss charges in the ISO tariff to this day and that the Commission, through its express powers under Part 9 of either version of the *Electric Utilities Act*, is statutorily obligated to provide the relief requested.[38]

48. The claimants also argue that the statutory procedure to complain about an ISO rule under Section 25 of the 2003 or 2003/07 *Electric Utilities Act* is a negative disallowance scheme as opposed to positive approval scheme - as those terms are understood in the jurisprudence. They cite *Nova, An Alberta Corporation* v. *Amoco Canada Petroleum Company Ltd.,* [1981] 2 SCR 437, 1981 CanLII 211 (SCC) (*Nova*) in support of the proposition that it would not constitute retroactive rulemaking for the Commission, after upholding a complaint that the Line Loss Rule is unlawful, to order that the rule be changed effective January 1, 2006 under the 2003 *Electric Utilities Act* (which is the later of the date the complaint was made and the date the impugned Line Loss Rule first came into effect). The claimants recognize that the effect of Section 25(9) of the 2003/07 *Electric Utilities Act* was to preclude the Commission from ordering that the Line Loss Rule be changed retroactively. Nevertheless the claimants argue that the line loss component of the ISO tariff could be changed with retrospective effect under either the 2003 or 2003/07 *Electric Utilities Act.* They say that, by extension, the Commission is authorized to change the line loss charges and credits flowing from the changed Line Loss Rule effective as of January 1, 2006. The claimants also cite the *TELUS Communications Inc.* v. *Canadian Radio-Television and Telecommunications Commission (CRTC),* 2004 FCA 365 (*Telus)* decision as authority for the propositions that (1) the Line Loss Rule was invalid from its inception and is thus a nullity; and (2) consequently, the Commission is both authorized and obligated to take remedial action by substituting a compliant Line Loss Rule for the rule found to be a nullity, and incorporating into the ISO tariff retroactive to January 1, 2006 the line loss charges and credits associated with the compliant Line Loss Rule. The claimants further cite the 2014 Alberta Court of Appeal decision in *ATCO Gas and Pipelines Ltd. v Alberta (Utilities Commission) 2014 ABCA 28 (Salt Caverns II)* as authority for the proposition that where market participants knew that line loss charges and credits in the ISO tariff were subject to change, any subsequent Commission order changing these rates does not constitute impermissible retroactive ratemaking. They say that (1) the August 2005 filing of Milner's complaint; (2) Milner's intervention in the AESO 2005/2006 GTA in which it sought to bring to the EUB's attention its concerns about the lawfulness of line loss charges produced by the Line Loss Rule; (3) the EUB's notice to "Interested Parties" in the covering letter to Decision 2005-096, in which it

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[37] Exhibit 547.01, AESO Argument, September 24, 2014, pages 6 to 14; exhibit 546.01, TCE Argument, September 24, 2014, pages 10 and 11, paragraphs 40 to 44; and exhibit 545.01, TransAlta Argument, September 24, 2014, page 9, paragraphs 43 and 45.

[38] Exhibit 549.01, Milner Argument, September 24, 2014, pages 11 to 25, paragraphs 52 to 106; and exhibit 548.01, ATCO Power Argument, September 24, 2014, pages 6 to 11, paragraphs 23 to 37.

advised that while it was not willing to consider Milner's "presentations" in the AESO's 2005/2006 GTA as the deadline for the submission of evidence had long since passed, was "without prejudice to Milner's right to pursue its complaint pursuant to Section 25 of the 2003 *Electric Utilities Act*"; and (4) many of the other legal and judicial proceedings summarized in the chronology of events in Section 2 of this decision, gave affected parties ample notice that the impugned line loss rates in the ISO tariff could be altered with retroactive effect.[39]

49. The respondents emphasize that the Commission's rulemaking and ratemaking authority is strictly prescribed by its governing legislation, citing *ATCO Gas & Pipelines Ltd.* v. *Alberta (Energy & Utilities Board),* [2006] 1 SCR 140, 2006 SCC 4 (*Stores Block*) and other decisions and case law to this effect. They identify separate and complementary sources of Commission legislative authority with respect to ISO rules generally and, more specifically, the line loss charges in the ISO tariff associated with the Line Loss Rule. These sources of authority include Section 25 of the *Electric Utilities Act* defining the Commission's authority to grant relief respecting the Line Loss Rule and Part 9, Division 2 of the *Electric Utilities Act* defining the Commission's authority and duties respecting the line loss charges recovered through the ISO tariff. The respondents contend that both the common law presumption against the retroactive application of legislation and the general prohibition against retroactive rate-making apply to this proceeding. They argue that the 2003/07 *Electric Utilities Act* governs the scope of the Commission's remedial authority in Phase 2 of this proceeding and that Section 25(9) plainly prescribes that any ISO rule change ordered by the Commission can only "come into effect" prospectively. Some of the respondents argue that any changes to line loss charges in the ISO tariff associated with the ISO Line Loss Rule must be equally prospective and that there is no authority for the Commission to award any compensation.[40] Others contend that final Commission approvals of ISO tariffs up to 2012 under Section 124 of the *Electric Utilities Act* limit the Commission's consideration of line loss charges resulting from the ISO Line Loss Rule to only those approved on an interim basis in the ISO 2013/2014 tariff.[41]

50. The respondents also contend that the Line Loss Rule was replaced as of January 1, 2009, with the result that a new complaint was then required in order for the Commission to have legislative authority to change the new Line Loss Rule. No such new complaint was filed until 2012. The respondents distinguish the *Nova* decision based on (1) the different legislative scheme governing the circumstances of that case and (2) their conclusion that the ratemaking provisions of the *Electric Utilities Act* (pursuant to which line loss charges in the ISO tariff are approved on a final basis) constitute a positive approval, as opposed to a negative disallowance, scheme thus rendering the findings in *Nova* inapplicable to this proceeding. They distinguish the *Telus* decision on the ground that the Canadian Radio-television and Telecommunications Commission's (CRTC) statutory powers and duties differ from those of the Commission under its governing legislation. In answer to the arguments made by the claimants based on the *Salt Caverns II* decision, several of the respondents maintain that the knowledge of affected parties that line loss rates might change retroactively, as required by that decision, must be knowledge derived from the actions or words of the regulator. Based on a review of the procedural record of Milner's complaint and the express language of Section 25(9) enacted in 2007, these respondents argue that no affected party could reasonably be said to have such knowledge prior to the

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39 Exhibit 559.01, Milner Reply Argument, October 22, 2014, page 14, paragraphs 62 and 63; and exhibit 560.01, ATCO Power Reply Argument, page 16, paragraph 48.

40 Exhibit 547.01, AESO Argument, September 24, 2014, pages 14 and 15.

41 Exhibit 543.01, Capital Power Argument, pages 11 and 12, paragraphs 48 to 55; and exhibit 542.01, ENMAX Argument, page 19, paragraphs 55 and 56.

Commission's decision to approve, on an interim basis, the line loss charges in the current 2013/2014 ISO tariff.

4 Commission findings

4.1 Status of the 2005 Milner complaint

51. Since the filing of Milner's original complaint, certain provisions of the 2003 *Electric Utilities Act* dealing with complaints about ISO rules have been amended: the 2004 *Transmission Regulation* was repealed; the 2007 *Transmission Regulation* was enacted; and the ISO's Line Loss Rule has also been amended. The respondents argue that these changes brought Milner's complaint to an end, either by the date the amendments to the 2003 *Electric Utilities Act* came into force on January 1, 2008 or, at the latest, by January 1, 2009, when the Line Loss Rule change came into effect. According to these respondents, for there to have been a valid and subsisting complaint against the Line Loss Rule after January 1, 2009, it was necessary for Milner, or some other market participant, to file a new complaint. Milner did so on June 11, 2012.

52. In its 2012 complaint filing, Milner stated that it considered its new complaint application completely redundant to its existing complaint and "without prejudice to and expressly preserving (a) the ongoing effectiveness and efficacy of Milner's complaint and (b) Milner's right to advance any and all arguments concerning the ongoing effectiveness and efficacy of Milner's Complaint[.]"[42] On July 30, 2012, ATCO Power filed a complaint on substantially the same grounds as the Milner complaint stating that it did not consider the filing of its complaint to be necessary because it had already participated in the complaint proceedings in support of Milner, and all of its submissions were "in substance, if not in form, a complaint of its own, which complaint has been before the Commission since no later than December 16, 2005."[43] ATCO Power continued: "Nevertheless, ATCO Power files this Complaint out of an abundance of caution, and without prejudice to any arguments ATCO Power may wish to make respecting (i) its status as a complainant throughout the Complaint Proceedings; and (ii) the ongoing nature and effect of the Complaint irrespective of any revisions or amendments to the Loss Factor Rule effective on or after January 1, 2009."[44]

53. The chronology of events respecting the *Electric Utilities Act*, the *Transmission Regulation* and the Line Loss Rule are set out in Appendix 3.

54. The Line Loss Rule was made by the AESO pursuant to its authority to make rules under Section 20 of the 2003 *Electric Utilities Act* and the 2004 *Transmission Regulation*. This rule came into effect on January 1, 2006. On August 17, 2005, after the rule had been made by the AESO but before it went into effect, Milner filed the complaint being considered in this proceeding with the Commission's predecessor, the EUB.

55. After a number of proceedings before the Commission and applications to court, the matter came before the Commission for determination. The Commission found in Decision 2012-104 and confirmed in Decision 2014-110 that the Line Loss Rule did not comply with

[42] Exhibit 311.01, Milner Second Complaint, June 11, 2012, page 5.
[43] Exhibit 573.00, ATCO Power Complaint, July 30, 2012, page 6, paragraph 20.
[44] Exhibit 573.00, ATCO Power Complaint, July 30, 2012, pages 7 and 8, paragraph 21.

sections 19(1)(a) and 19(2)(d) of the 2004 *Transmission Regulation* or with Section 25(6)(b) of the 2003 *Electric Utilities Act* because the rule employed the AESO's MLF/2 methodology which results in a rule that disadvantages loss savers and does not properly charge loss creators for their losses.

56. The 2004 *Transmission Regulation* was repealed and replaced by the 2007 *Transmission Regulation*, which came into effect on April 30, 2007. The 2007 *Transmission Regulation* made certain changes to how line loss factors were to be adjusted as of January 1, 2009, but did not change sections 19(1)(a) or 19(2)(d), other than renumbering them as sections 31(1)(a) and 31(2)(d), respectively.

57. The AESO made changes to the 2005 Line Loss Rule in 2007. These changes were approved by the AESO Executive Rules Committee on November 8, 2007.[45] The consultation record (filed by the AESO in this proceeding)[46] dealing with the Line Loss Rule describes the changes that the AESO was proposing to make at that time as "modifications" and "amendments" rather than the making of a "new" ISO rule and replacing an existing rule. These amendments or modifications reflected the changed range of line loss factors permitted by the "collars" specified in the 2007 *Transmission Regulation*. These changes were to become effective as of January 1, 2009. None of these changes altered the MLF/2 methodology.

58. The consultation record indicates further that on October 2, 2012, the AESO filed an expedited ISO rule[47] under Section 20.6 of the 2003/07 *Electric Utilities Act* to replace the Line Loss Rule (that had been amended effective January 1, 2009).[48] The AESO's notice of filing to the Commission stated that it was a redrafted and relocated rule entailing no material change to the existing ISO Line Loss Rule. In particular, neither the MLF/2 methodology nor any other part of the Line Loss Rule was changed.

59. The Commission has considered the arguments of a number of the respondents that changes to the *Electric Utilities Act*, the *Transmission Regulation* or the Line Loss Rule itself between August 17, 2005 and today resulted in the Milner complaint coming to an end and, as a result, that Milner was required to file a new complaint at the happening of one or more of those events. The Commission disagrees and finds that, for the purposes of the Milner complaint:

- the Line Loss Rule has not been replaced by a new rule and has continued in all relevant respects since it was put into effect January 1, 2006 because it still employs the MLF/2 methodology;

- the relevant portions of the *Transmission Regulation* have not changed during all times relevant to this proceeding because sections 19(1)(a) and 19(2)(d), which are the sections of the regulation with which the Line Loss Rule does not comply, have not changed other than to be renumbered as sections 31(1)(a) and 31(2)(d).

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45 Exhibit 533.02, AESO Line Loss Consultation, September 5, 2014, pdf page 559.

46 The consultation record is the record of all consultations in which the AESO engaged to develop the Line Loss Rule and any adjustments to that rule on account of changes to regulations or legislation. The consultation record was filed in response to a request by the Commission and is filed as Exhibit 533.02.

47 ISO rules Section 501.10: *Transmission Loss Factor Methodology and Requirements*

48 Exhibit 533.02, AESO Line Loss Rule Consultation, September 5, 2014, pdf page 954.

60. Under Section 25(6)(b) of the 2003 *Electric Utilities Act*, the Board could, on complaint, order the ISO to revoke or change a provision of an ISO rule if it found the rule to be "unjust, unreasonable, unduly preferential, arbitrarily or unjustly discriminatory or inconsistent with or in contravention of this Act or the regulations." The Commission made such a finding twice. Once in Decision 2012-104 and again in Decision 2014-110.

61. The 2003/07 *Electric Utilities Act* included a change to the test to be met by complainants challenging an ISO rule. Section 25(4.1) of the 2003/07 *Electric Utilities Act* states that when a market participant complains about a rule that is in effect at the time of the complaint, the complainant has the onus of proving that "the ISO rule is technically deficient … does not support the fair, efficient and openly competitive operation of the market, or … is not in the public interest." Section 20.4(1)(b)(c) and (d) provides for the same test to be applied to objections to new ISO rules. A number of the respondents[49] argued that they had not had an opportunity in the proceeding leading to Decision 2012-104 to address whether the Line Loss Rule contravened this new standard. The Commission granted the review of that decision, in part, on this ground. However, none of the respondents argued in this proceeding that the Line Loss Rule would survive a complaint under the 2003/07 *Electric Utilities Act* test.

62. While the test for relief in the 2003/07 *Electric Utilities Act* is stated differently, it is to the same effect for the purposes of considering the Milner complaint. The Commission found that the Line Loss Rule is in contravention of sections 19(1)(a) and 19(2)(d) of the 2004 *Transmission Regulation*, and the corresponding provisions of the 2007 *Transmission Regulation.* In the Commission's view, a rule that contravenes an Act of the legislature or a regulation, cannot be in the public interest. The Line Loss Rule contravenes the *Transmission Regulation* and is, therefore, not in the public interest. The Commission also finds, on the basis of the record of this proceeding that the Line Loss Rule does not support the fair, efficient and openly competitive operation of the market. The Commission bases this finding, *inter alia*, on its finding in Decision 2014-110 (and Decision 2012-104) that the Line Loss Rule arbitrarily and unjustly discriminates against loss savers. Therefore, the Line Loss Rule fails the tests for relief set out in each of the 2003 *Electric Utilities Act* and the 2003/07 *Electric Utilities Act* at all relevant times since it went into effect January 1, 2006.

63. Based on the forgoing analysis and findings, the Commission further finds that Milner's complaint continues and has continued uninterrupted from the date it was filed on August 17, 2005. The Commission also finds that the requirements of sections 19(1)(a) and 19(2)(d) of the *Transmission Regulation*, with which the Line Loss Rule is non-compliant, remain in effect today (albeit renumbered as sections 31(1)(a) and 31(2)(d) of the 2007 *Transmission Regulation*) and have remained in effect uninterrupted at all times relevant to the Milner complaint. The Commission also finds that the non-compliant provisions of the Line Loss Rule remain in effect today and have remained in effect and non-compliant uninterrupted since January 1, 2006.

64. Having made these findings, it remains for the Commission to determine whether the 2003 *Electric Utilities Act* or the 2003/07 *Electric Utilities Act*, or both, permit the Commission to order a remedy or relief to correct for the payment or receipt of unlawful line loss charges and credits included in the ISO tariff on account of any period for which the Commission finds that the Line Loss Rule has been non-compliant. To make this determination, the Commission

[49] AUC Decision 2013-159, pages 4-5, paragraphs 9–12.

examines the rulemaking (including complaint and, to the extent applicable, objection) provisions and tariff provisions of the 2003 *Electric Utilities Act* and 2003/07 *Electric Utilities Act* as well as the *Interpretation Act* RSA 2000 c 1-8 (*Interpretation Act*) and applicable common law.

4.2 Scheme of the legislation

65. In order to determine whether the Commission may order a remedy or relief, the Commission first examines the statutory scheme of both the 2003 and 2003/07 *Electric Utilities Act*. Then, taking into account the factual circumstances underlying the history of the Milner complaint and the legislative history of the *Electric Utilities Act*, the Commission must consider which (or whether both) of the 2003 and 2003/07 *Electric Utilities Act* govern the Commission's determinations in this proceeding.

66. In conducting its review and analysis of the statutory scheme of the 2003 *Electric Utilities Act* and the 2003/07 *Electric Utilities Act*, the Commission has relied on the modern principle of statutory interpretation enunciated and upheld by the courts and various authorities in the following terms:

> The modern principle of statutory interpretation requires "the words of an Act be read in their entire context and in their grammatical and ordinary sense harmoniously with the scheme of the Act, the object of the Act and the intention of Parliament": *Rizzo & Rizzo Shoes Ltd. (Re)*, [1998] 1 S.C.R. 27, 154 D.L.R. (4th) 193 at para. 21 quoting Driedger in *Construction of Statutes* (2nd ed. 1983) at 87. The interpretation of the plain wording must pay sufficient attention to the scheme of the Act, its object and the intention of the legislature: *Rizzo* at para. 23.[50]

67. Also, in *Sullivan on the Construction of Statutes*, Fifth Edition, at page 359:

> [W]hen words are read in their immediate context, the reader forms an initial impression of their meaning. … But any impression based on immediate context must be supplemented by considering the rest of the Act, including the other provisions of the Act and its various components.

68. Further, at page 364, the author notes:

> When analyzing the scheme of the Act, the court tries to discover how the provision or parts of the Act work together to give effect to a plausible and coherent plan. It then considers how the provision to be interpreted can be understood in terms of that plan. … The fundamental presumption in scheme analysis is being able to grasp and explain the basic structure on which the Act is built and how the various parts and provisions were meant to function within this structure to achieve the desired goal, or more often, the desired mix of goals.

69. Since the Commission is called upon to consider the effect of the 2007 amendments to the 2003 *Electric Utilities Act* on the questions before it in this proceeding, the Commission has also considered the relevant provisions of the *Interpretation Act*.

70. A complete copy of the relevant provisions of the 2003 *Electric Utilities Act* and 2003/07 *Electric Utilities Act* are provided in Appendix 4 to this decision, as are relevant sections of the *Interpretation Act*.

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50 *Milner*, paragraph 32.

4.2.1 2003 *Electric Utilities Act* ISO rulemaking provisions

71. The ISO's statutory duties are set out in sections 16 to 18 of the 2003 *Electric Utilities Act*. Among them is the duty to "manage and recover the costs of transmission line losses" (Section 17(e)). The 2003 *Electric Utilities Act* provides the ISO with two alternative mechanisms by which to recover the costs of line losses. It can include them in the ISO tariff or it can establish and charge ISO fees (Section 30(4)). The AESO has consistently recovered the costs of line losses through the ISO tariff by establishing an ISO rule that determines line loss factors which are then converted (by means of a simple calculation) into line loss charges in the ISO tariff. Section 19(1) of the 2004 *Transmission Regulation* proceeds from the assumption that the AESO has chosen to proceed under the rulemaking and tariff option and instructs the ISO on how to make a rule dealing with line losses. Sections 20 to 25 of the 2003 *Electric Utilities Act* define the ISO's rulemaking authority and the recourse available to market participants seeking to challenge an ISO rule or a related ISO enforcement order. Sections 18 and 19 of the 2003 *Electric Utilities Act* also deal, at least in part, with ISO rules, but are not relevant to the discussion here.

72. Section 20(1) of the 2003 *Electric Utilities Act* states that the ISO may make rules. Rules are made by the ISO when they are approved by the AESO's Executive Rules Committee which was delegated the authority to consider and approve ISO rules by the AESO Board.[51]

73. It is clear from Section 20(1) that the scope of the ISO's rulemaking authority is very broad. Almost all of the matters in respect of which rules can be made are technical or operational in nature. Nowhere in Section 20(1), for example, is the ISO expressly granted the power to make rules determining the line loss charges that are to be recovered from individual generating units or groups of generating units through the ISO tariff. The ISO's authority to make rules that determine rates to be charged in the ISO tariff is instead found in the "basket clause" at the end of Section 20(1). Specifically, Section 20(1)(l) provides that the ISO may make rules respecting "any other matter the Independent System Operator considers necessary or advisable to carry out its duties, responsibilities and functions under this Act and the regulations." Reference must then be had to Part 5 of the 2004 *Transmission Regulation*, which sets out the ISO's responsibility to develop line loss rules that recover the costs of transmission line losses both in the aggregate and from each respective generating unit or group of generating units relative to load. Sections 19(1)(a) and 19(2)(d), in particular, specify what must be taken into account in developing line loss rules and determining line loss factors.

74. The rulemaking provisions of the 2003 *Electric Utilities Act* are silent with respect to the effective date of an ISO rule. It would appear from Section 20(3) that a rule comes into force, and all market participants must comply with it, on the date the AESO says it is to take effect.

75. No prior EUB review or approval is required for an ISO rule to come into effect. However, there are a number of safeguards in the 2003 *Electric Utilities Act* designed to protect market participants from the imposition of unlawful rules. These safeguards originate through the complaint process. Under the 2003 *Electric Utilities Act*, any person, including a market participant subject to an ISO rule, has the right under Section 25 to challenge the lawfulness of any ISO rule by way of written complaint. The 2003 *Electric Utilities Act* provides for a number

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[51] Exhibit 533.02, Line Loss Rule Consultation Record – Attachment "May 25, 2005 AESO letter to market participants re Loss Factor Rules Issues", document dated May 25, 2005, pdf page 72.

of remedies if the complaint is upheld by the Board and provides for safeguards while the complaint is being considered. Section 25 of the 2003 *Electric Utilities Act* provides as follows:

> **Complaints to the Board**
>
> **25(1)** Any person may make a written complaint to the Board about
>
> (a) an ISO rule,
>
> (b) an ISO fee, or
>
> (c) an ISO order.
>
> **(2)** A complaint about an ISO fee or an ISO order must be made within 60 days of the date the market participant receives notice of the fee or order.
>
> **(3)** Before dealing with any complaint, the Board may require the person making the complaint and the Independent System Operator to attempt to negotiate a settlement of the matter or participate in a dispute resolution process selected by the Board.
>
> **(4)** The Board may, by giving written notice with reasons to the person making the complaint, decline to investigate a matter or hold a hearing, or terminate an investigation or hearing, if the Board considers
>
> (a) the complaint is frivolous, vexatious, trivial or otherwise does not warrant investigation or a hearing;
>
> (b) the complaint or the substance of it has been referred to, should be referred to, or is the subject of an investigation by, the Market Surveillance Administrator;
>
> (c) the complaint or the substance of it has been investigated by the Market Surveillance Administrator, has been the subject of a tribunal hearing or has been the subject of a tribunal order;
>
> (d) the subject-matter of the complaint is under the jurisdiction of another authority.
>
> **(5)** Unless the Board otherwise orders, a complaint under this section does not relieve the person making the complaint from the obligation
>
> (a) to pay an ISO fee pending a decision of the Board, or
>
> (b) to comply with an ISO order or ISO rule pending a decision of the Board.
>
> **(6)** If the Board decides to hear the complaint, the Board may, by written decision giving reasons,
>
> (a) determine the justness and reasonableness of
>
> (i) an ISO fee, or
>
> (ii) an ISO order
>
> and may confirm, change or revoke the fee or order;
>
> (b) order the Independent System Operator to revoke or change a provision of an ISO rule that, in the Board's opinion, is unjust, unreasonable, unduly preferential,

> arbitrarily or unjustly discriminatory or inconsistent with or in contravention of this Act or the regulations;
>
> (c) dismiss the complaint;
>
> (d) direct the Independent System Operator to reimburse a market participant any fee paid to the Independent System Operator;
>
> (e) direct the Balancing Pool to reimburse a market participant any administrative penalty paid to the Balancing Pool in accordance with an ISO order.

76. Section 25(1) of the 2003 *Electric Utilities Act* provides that any "person" may make a written complaint to the Board about an ISO rule, an ISO fee or an ISO order. Pursuant to Section 25(2), complaints about ISO fees or orders must be made within 60 days of the date the "market participant" receives notice of the fee or order.[52] By comparison, there is no time limit for a "person," including a "market participant," to file a written complaint about an ISO rule.

77. Under the 2003 *Electric Utilities Act* the mere act of filing a written complaint is not sufficient to place the impugned rule in abeyance or to prevent a prospective rule from taking effect pending the outcome of the complaint proceeding.[53] Section 25(4)(a) provides that the Board may decline to investigate a complaint or to hold a hearing with respect to a complaint if it considers the complaint "is frivolous, vexatious, trivial or otherwise does not warrant investigation of a hearing."[54] If the Board decides to hear a complaint about an ISO rule, and subsequently finds the complaint to be valid, then pursuant to Section 25(6)(b), it may, "by written decision giving reasons, order the Independent System Operator to revoke or change a provision of an ISO rule …" Alternatively, the Board, following a hearing, may decide to dismiss the complaint (Section 25(6)(c)). The 2003 *Electric Utilities Act* is silent with respect to the effective date of an ISO rule that the Board has ordered the ISO to change. In particular, there is no express prohibition against making a retroactive change to an ISO rule where the Board has found the rule to be unlawful after holding a hearing on a complaint, whether the Board orders that the rule be changed or revoked.

78. As noted above, Section 20(3) of the 2003 *Electric Utilities Act* requires all market participants to "comply with ISO rules." Section 21(3) is of similar effect with respect to ISO fees. It requires all market participants that have been charged an ISO fee to pay it. Notwithstanding these obligations to comply with existing ISO rules and to pay ISO fees that have been charged, the 2003 *Electric Utilities Act* provides a measure of protection to market participants from (potentially) unjust and unreasonable fees and rules pending the determination of complaints filed against such fees and rules. The first protection is that Section 25(5) allows the EUB to relieve a complainant from the "obligation to comply with an ISO order or an ISO rule pending a decision of the Board." This relief, if granted, means that should a determination

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52 Later revisions to Section 25 of the *Electric Utilities Act* replaced the word "person" with "market participant."
53 See for example Sections 20(3), 21(3) and 25(5) of the 2003 *Electric Utilities Act*.
54 It was on the basis of Section 25(4)(a) that the Board summarily dismissed Milner's complaint in Decision 2005-150 issued on December 30, 2005.

eventually be made by the Board that the impugned rule is unlawful, no additional remedy need be provided to the complainant (at least to the date the relief was granted).[55]

79. The second protection from unjust or unreasonable fees or rules is that the 2003 *Electric Utilities Act* precludes enforcement of any impugned fees or rules pending the determination by the Board of a complaint against an ISO order seeking to (1) compel compliance with a rule, (2) compel payment of a fee, or (3) to impose an administrative penalty for non-compliance with a rule or non-payment of a fee.

80. The following sections describe how this scheme operates. The primary mechanism by which compliance with ISO rules and payment of ISO fees is enforced under the 2003 *Electric Utilities Act* is an ISO order.

ISO orders

> **22(1)** If the Independent System Operator is satisfied that a market participant has contravened an ISO rule or failed to pay an ISO fee, the Independent System Operator may, by order, do one or more of the following:
>
> (a) impose an administrative penalty on the market participant of not more than $100 000 a day for each day on which a contravention occurs or continues;
>
> (b) deny, suspend, restrict or terminate the right of a market participant to exchange electric energy through the power pool or to participate in any other market operated by the Independent System Operator;
>
> (c) impose another sanction that the Independent System Operator considers appropriate;
>
> (d) order compliance with the ISO rule or payment of an ISO fee.

81. Pursuant to Section 22(1), the ISO can, among other things, order a market participant to comply with a rule, pay an ISO fee, or impose an administrative penalty for non-compliance with a rule or failure to pay an ISO fee. However, pursuant to Section 22(3) of the 2003 *Electric Utilities Act*, the market participant can then make a complaint to the Board about the enforcement order under Section 25(1).

82. Section 23(1) of the 2003 *Electric Utilities Act* provides that:

> 23(1) Subject to the right to make a complaint under section 25, if a person fails to pay an administrative penalty in accordance with the order imposing it, the Independent System Operator may file a copy of the order with the clerk of the Court of Queen's Bench, and on being filed, the order has the same force and effect and may be enforced by the Independent System Operator as if it were a judgment of the Court.
> [Emphasis added]

83. Similarly, Section 23(2) of the 2003 *Electric Utilities Act* provides that:

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[55] While no such relief was ever provided to Milner, there was clear provision for such in the legislation, although, given the nature of the Line Loss Rule, it is not clear how only one generator could be relieved of complying with the Line Loss Rule without affecting all other generators. In the circumstances of the Line Loss Rule, it would be unlikely that the Board could exempt only one generator.

> (2) Subject to the right to make a complaint under section 25, the Independent System Operator may apply to the Court of Queen's Bench to enforce an ISO order, other than an order to pay an administrative penalty, on giving notice of the application to the person against whom enforcement is sought, in accordance with the *Alberta Rules of Court*. [Emphasis added]

84. Meanwhile, Section 23(4)(a) of the 2003 *Electric Utilities Act* provides that:

> (4) The Court of Queen's Bench may give judgment enforcing an ISO order unless
>
> (a) the order is the subject of complaint under section 25 that has not been decided.

85. In other words, the ISO's authority to enforce its orders against a market participant is constrained by that person's right to make a complaint against the order itself (as distinct from a complaint against the underlying fee or rule) and that where the ISO turns to the Court of Queen's Bench to enforce an order against non-compliance with a rule or failure to pay a fee, the court itself is precluded from giving judgment until a determination has been made by the Board with respect to the impugned order.

86. Taken together, these provisions suggest that while an ISO rule takes effect on the date the ISO specifies in the notice of the rule, it cannot be enforced if a complaint has been made but no decision has yet been issued by the Board with respect to the complaint. Issuing a compliance order, or an order to pay an administrative penalty for failure to comply with a rule or to pay a fee, while an initial complaint against a rule or fee is still being determined, would not assist the ISO in enforcing the rule or fee. This is because a new complaint – this time against the compliance order or order imposing an administrative penalty – would effectively render such an order unenforceable pending a determination on both complaints.

87. The Commission also takes note of the specific wording of sections 23(1) and 23(2). Both begin with the words "(s)ubject to the right to make a complaint under section 25." These sections could have been drafted differently without affecting the manner in which they operate and/or interact with other provisions of the 2003 *Electric Utilities Act*. For example, they could have begun with the words, "(s)ubject to a complaint having been made under section 25," or "(s)ubject to section 23(4) and section 25 herein" or words to similar effect. Yet, the legislature chose to expressly define as a "right" a person's ability to make a complaint under Section 25, and to expressly constrain the ISO's ability to enforce a compliance order by making it subject to a person's right to make a complaint under Section 25. The combination of the right of market participants to make a complaint about a bad fee or a bad rule and the inability of the AESO to enforce the fee or rule once a complaint has been made, provides significant protection for market participants that are subject to bad rules.

88. The exercise of the right to complain is a significant protection. After the EUB refused to hear the Milner complaint in Decision 2005-150, Milner appealed the decision to the Alberta Court of Appeal. The court allowed Milner's appeal, vacated the Board's decision dismissing Milner's original complaint and remitted the matter to the Board to continue to further investigate or hold a hearing to determine whether there was a contravention of Section 19 of the 2004 *Transmission Regulation* as alleged.

89. The Court of Appeal rendered its decision only after carefully considering the scheme of the 2003 *Electric Utilities Act*, including especially Section 25 and the "breadth of a

complainant's right to be heard."[56] In its Memorandum of Judgment dated July 29, 2010, the Court of Appeal made the following key findings:

> There is no doubt that the Board can decide questions of law. We also recognize that where a question of interpretation of law falls within the Board's expertise, deference may be owed to that interpretation. See: *Canada (Citizenship and Immigration) v. Khosa*, 2009 SCC 12, [2009] 1 S.C.R. 339 at para. 25; *Nolan v. Kerry (Canada) Inc.*, 2009 SCC 39, [2009] 2 S.C.R. 678 at para. 29. Here, however, the nature of the question does not turn on the Board's expertise or its familiarity with the legislation. Rather, it lies at the heart of the complaint process, and affects the breadth of a complainant's right to be heard.
>
> The AESO has been given extensive powers which can impact dramatically on complainants such as Milner. Its powers must be exercised within any relevant statutory and regulatory limits and are subject to complaint to the Board pursuant to sections 25 and 26. Section 25 allows any person to make a written complaint to the Board about an ISO rule, an ISO fee, or an ISO order. <u>The remedial power provided under section 25 is also instructive on the breadth of the right to complain.</u> Pursuant to section 25(6), following a hearing, the Board can determine whether an ISO order is "unjust, unreasonable, unduly preferential, arbitrarily or unjustly discriminatory or inconsistent with or in contravention of this Act or the regulations". In addition, section 26 allows for complaints about an ISO's conduct. Although the AESO may consult prior to making rules, <u>there is no legislated right for an affected party to a hearing in front of the AESO. As a result, the complaint process before the Board is more than one of an appeal or judicial review. It is the right to question a rule or fee of the AESO.</u>[57]
>
> [Emphasis added]

90. The Court of Appeal then proceeded to examine the reasons given by the EUB in dismissing Milner's complaint and found that the Board had misconstrued the scheme of the 2003 *Electric Utilities Act* in giving too much deference to the AESO and, in effect, setting too high a bar or threshold for hearing complaints against ISO rules:

> This reasoning suggests that the Board based its decision, in part, on the fact that the AESO had been delegated the responsibility to develop these line loss rules and therefore it was entitled to deference even at this early stage of a complaint. That cannot be the case.
>
> The fact that the AESO had been delegated the responsibility of setting a line loss rule and managing and recovering costs for transmission line losses is irrelevant to the complaint and review process for questioning the AESO's decisions and actions in performing its delegated duty. The fact that the AESO has delegated power to manage, does not mean that power is not subject to the complaint process. To use the fact the AESO had been delegated power as somehow requiring deference to its decisions at this early stage of evaluating a complaint for merit is to engage the concept of deference at the wrong time and place. <u>The AESO's authority is limited by the complaint process. If that process can be bypassed before investigation by deferring to its authority, then the legislative safeguard is completely undermined.</u> The Board has

[56] *Milner*, paragraph 27.
[57] *Milner*, paragraphs 27-28.

> given deference at a point where deference is not due, notwithstanding its statement of an acceptable test.[58]
> [Emphasis added]

91. The Court of Appeal was very clear that the legislative safeguards that counterbalance the ISO's authority to make rules without need of prior Board review or approval must be allowed to operate as intended. In the case of the EUB's refusal to hear the Milner complaint, that meant the threshold for the Board to hear complaints or investigate them further could not be so high as to frustrate the same legislative design that relies on the complaint process as a safeguard of the public interest in the rulemaking process.

92. This legislative design balancing (1) the ISO's responsibility for, and technical competence in, developing rules against (2) the right of market participants to challenge those rules as being unjust or unreasonable or otherwise in contravention of the applicable legislation or regulations is also apparent in the safeguards established in Section 23 of the 2003 *Electric Utilities Act* dealing with the enforcement of ISO orders. These provisions, discussed above, when examined both in the context of the 2003 *Electric Utilities Act's* rulemaking provisions and within the overall scheme and design of the 2003 *Electric Utilities Act* and regulations, provide an additional measure of protection to parties that may be adversely affected by a rule they believe to be unlawful or otherwise contrary to the legislation and regulations. They do so by restricting the ability of the ISO and the courts to enforce ISO compliance orders against, or orders imposing administrative penalties upon, market participants pending the outcome of the complaint process initiated by those parties pursuant to their statutory right to challenge such orders (and the underlying rules or fees in respect of which such orders are made).

93. There are further specific safeguards dealing with ISO fees and ISO administrative penalties assessed against market participants. Where the Board has heard a complaint about an ISO fee (or an order compelling payment of an ISO fee) or an ISO order imposing an administrative penalty on a market participant, sections 25(6)(d) and (e) authorize the Board to direct the AESO to reimburse a market participant any ISO fee it has paid or to direct the Balancing Pool to reimburse a market participant any administrative penalty paid to the Balancing Pool in accordance with an ISO order, respectively. There is no express provision in the rulemaking sections of the 2003 *Electric Utilities Act* that deals with reimbursement or other settlement in the event that a rule-based tariffed charge is found unlawful or non-compliant.

4.2.2 2003 *Electric Utilities Act* ratemaking provisions

94. The duties and powers of the Board with respect to ratemaking are set out in Part 9, Division 2 of the 2003 *Electric Utilities Act*. The ratemaking provisions of the Act apply to all tariffs subject to Board approval, not just the ISO tariff.

95. Central to the Board's ratemaking authority is Section 121. It states, in relevant part, as follows:

> **Matters the Board must consider**
>
> **121(1)** On giving notice to interested parties, the Board must consider each tariff application.

[58] *Milner*, paragraphs 51-52.

> **(2)** When considering whether to approve a tariff application the Board must ensure that
>
> (a) the tariff is just and reasonable,
>
> (b) the tariff is not unduly preferential, arbitrarily or unjustly discriminatory or inconsistent with or in contravention of this or any other enactment or any law…

96. Sections 124 and 125 of the *Electric Utilities Act* are also important. Pursuant to Section 124 of the 2003 *Electric Utilities Act*, the Board, in respect of each tariff application, may approve a tariff in whole or in part, with or without changes, or refuse to approve a tariff or any part of it. Section 125 of the 2003 *Electric Utilities Act*, meanwhile, deals specifically with ISO tariffs. It provides that the ISO "shall not put into effect a tariff that has not been approved by the Board." Together, sections 121, 124 and 125 ensure that all ISO tariffs must be just and reasonable and that no ISO tariff can take effect until it has been approved by the Board.

97. However, there are other provisions that deal specifically with the ISO tariff. The constituent elements of the ISO tariff are described in Section 30 of the 2003 *Electric Utilities Act*. That section, together with Section 119(4) of the 2003 *Electric Utilities Act*, requires that the ISO apply to the EUB for approval of its tariff.

98. The ISO tariff is not a normal tariff. There is a specific section in the Act that deals only with the ISO tariff (Section 30). The costs that underpin many of the rates or charges approved under that tariff are not reviewable by the Board except on complaint. In some cases, such as the line loss charge components of the ISO tariff, the actual calculation of the charges is carried out in accordance with an ISO rule which is not reviewable by the Board except on complaint. In other words, while Section 30(4) of the 2003 *Electric Utilities Act* allows for the ISO to recover the costs of transmission line losses it considers prudent through the ISO tariff, there is no avenue through which the Board could examine the line loss charge components of the ISO tariff unless a complaint was filed about the Line Loss Rule. If no complaint was filed, the Board would simply have to accept that component of the ISO tariff. Accordingly, while the general tariff provisions in the 2003 *Electric Utilities Act* apply to the ISO tariff, the Board's powers to deal with the line loss charge components of the ISO tariff are constrained by specific provisions of the legislation.

99. The Board chose not to hear the Milner complaint in the tariff process in 2005 and then proceeded to hear the complaint in a separate proceeding. After dismissing the complaint (which was subsequently successfully appealed) the Board allowed that the ISO was free to implement its rule, which was a rule employed to establish line loss charges in the ISO tariff.

4.2.3 2003/07 *Electric Utilities Act* ISO rulemaking provisions

100. To a considerable extent, the ISO rulemaking provisions in the 2003/07 *Electric Utilities Act* parallel those found in the *2003 Electric Utilities Act*. The principal duties and responsibilities of the ISO are set out in sections 16 to 18 of the 2003/07 *Electric Utilities Act*.[59] Like in the 2003 *Electric Utilities Act*, the ISO may choose to employ a fee or a rule that

[59] They are very similar to the corresponding provisions of the 2003 *Electric Utilities Act*, with the exception of Section 16.1, which is a new provision (and not relevant to the current proceeding) requiring that the ISO act in accordance with any applicable *Alberta Land Stewardship Act* regional plan.

determines charges in a tariff for the collection of line loss costs. However, there are important differences as well. The core provisions of the 2003/07 *Electric Utilities Act* dealing with ISO rules are found in Sections 19 to 26.

101. The principal differences between the 2003 and 2003/07 *Electric Utilities Acts* are:

1. The 2003/07 *Electric Utilities Act* bifurcates the complaint process found in the *2003 Electric Utilities Act* into "objections" which can be made prior to the time a rule takes effect and "complaints" that can only be made after a rule takes effect.[60] The objection provisions found in sections 20.4 and 20.3(b) of the 2003/07 *Electric Utilities Act* effectively preclude a proposed non-expedited rule from taking effect until the Commission has dealt with the objection. No such provisions were included in the *2003 Electric Utilities Act*.

2. The 2003/07 *Electric Utilities Act* also introduced in Section 20.6 a provision dealing with expedited ISO rules. This provision authorizes the ISO to bring into effect, on an expedited basis, an ISO rule that in the opinion of the ISO is urgent, or for which there are "other sufficient reasons that require that the ISO rule take effect expeditiously." Expedited rules take effect on the later of the date on which they are filed with the Commission and the date specified in the ISO rule.

3. The 2003/07 *Electric Utilities Act* introduced a new test of what needs to be proven by a market participant filing a notice of objection to an ISO rule or a complaint against an ISO rule. This test is discussed above in paragraph 61 of this decision and need not be discussed further here.

4. The 2003/07 *Electric Utilities Act* expressly requires that all proposed ISO rules be filed with the Commission and clearly sets out when they can take effect.

5. Under Section 25(9) of the 2003/07 *Electric Utilities Act* when a rule has been changed in response to a Commission direction made following a complaint against a rule that "is in effect" that change cannot be made retroactively.

102. Section 20.2(1) of the 2003/07 *Electric Utilities Act* requires that the ISO file with the Commission any ISO rule made under section 19 or 20. Section 20.2(2), in turn, requires that the Commission publish notice of the filing of an ISO rule within five days.

103. Section 20.3 deals with the effective date of non-expedited ISO rules. It provides as follows:

> **Effective date of ISO rules**
>
> **20.3** Except as otherwise provided by section 20.6,

[60] The Commission notes here that the 2003/07 *Electric Utilities Act* appears to preclude complaints against ISO rules being made during the period between the expiry of the deadline to file notice of an objection and the date that a proposed rule is to take effect.

(a) if no notice of objection is filed under section 20.4, the ISO rule takes effect on the later of the day specified in the ISO rule and the 10th day after the day on which notice of the ISO rule is published, or

(b) if a notice of objection is filed under section 20.4,

(i) where the ISO rule is confirmed, the ISO rule takes effect on the latest of

(A) the day on which an order is made confirming the ISO rule,

(B) the day specified in the ISO rule, and

(C) the day otherwise ordered by the Commission,

or

(ii) where the ISO rule is changed pursuant to an order under section 20.5(1)(c), the ISO rule takes effect in accordance with section 20.5(4).

104. The most significant change introduced by Section 20.3 is that if a notice of objection to a proposed non-expedited ISO rule is filed with the Commission within 10 days of the date on which the Commission published the notice of the ISO rule having been filed, the earliest date on which the proposed ISO rule can take effect is the date on which the Commission confirms the ISO rule after holding a hearing to consider the objection. However, if after holding a hearing to consider the objection, the Commission determines that the proposed rule must be changed before it can come into effect, Section 20.5(4) provides that the earliest effective date of the new or revised rule is the latest of (1) the date on which the new rule is filed, (2) the date specified in the ISO rule, or (3) the date otherwise ordered by the Commission.

105. In other words, Section 20.3 of the 2003/07 *Electric Utilities Act* (operating in tandem with sections 20.4 and 20.5 which describe how an objection to an ISO rule can be made and the Commission's remedial powers upon hearing an objection) acts as a prohibition against the coming into effect of a non-expedited ISO rule until the objection is heard by the Commission and a determination is made. This is a stronger protection than the provisions in the 2003 *Electric Utilities Act* which merely made a rule unenforceable while a complaint filed before a rule went into effect (or after the rule went into effect) was being considered. The Commission has no authority to decline to hear an objection to an ISO rule. This is different from the 2003 *Electric Utilities Act* which permitted the Board to decline to hear a complaint whether made before the rule came into effect (such as the Board's refusal to hear the Milner complaint) or after the rule came into effect.

106. Section 20.6 of the 2003/07 *Electric Utilities Act* allows the ISO to expedite the implementation of a rule if it is urgent or if there are other sufficient reasons to expedite the rule. Section 20.6 of the 2003/07 *Electric Utilities Act,* to the extent that it is relied upon by the AESO, can be interpreted as diminishing the effectiveness of the safeguard simultaneously introduced by the legislature when it enacted the objection provisions in sections 20.2 to 20.5 of the 2003/07 *Electric Utilities Act*.

107. Section 20.1 of the 2003/07 *Electric Utilities Act* contains certain important transitional provisions. Specifically, Section 20.1 expressly states that the new provisions of the 2003/07 *Electric Utilities Act* dealing with objections to ISO rules, namely, sections 20.3 to 20.5, "do not apply to an ISO rule that was made before the coming into force of those sections." The

objection provisions of the 2003/07 *Electric Utilities Act* came into force on January 1, 2008. The Line Loss Rule, meanwhile, was made in 2005 but did not come into effect until January 1, 2006. Milner's original complaint was also filed in 2005, several months before the Line Loss Rule took effect. Thus, the objection provisions of the 2003/07 *Electric Utilities Act* are of no assistance to Milner even though the "complaint" Milner filed in 2005 would have been an "objection" had the 2003/07 *Electric Utilities Act* been in force at the time and, as noted above, the Board would not have been able to decline to hear the objection and the rule would not have come into effect until, at the very earliest, the Board had conducted a hearing into the objection.

108. Many parties appear to consider that Section 25 of the 2003/07 *Electric Utilities Act* is the successor provision to the complaints provisions of Section 25 of the 2003 *Electric Utilities Act*. But it is not. It does not deal with all of the situations to which Section 25 of the 2003 *Electric Utilities Act* applies. Unlike Section 25 of the 2003 *Electric Utilities Act*, Section 25 of the 2003/07 *Electric Utilities Act* deals only with complaints made about rules that are in effect. Indeed, there is no provision in the 2003/07 *Electric Utilities Act* for the filing of a complaint before the rule goes into effect. Instead, there are new sections dealing with objections before a rule is in effect that take the place of the opportunity for complaints to be made before a rule takes effect under the 2003 *Electric Utilities Act*. The objection provisions also replaced safeguards in the complaint provisions of the 2003 *Electric Utilities Act*.

109. With the bifurcation of the ISO rule complaint provisions into separate objections (before the rule goes into effect) and complaints (after the rule is in effect), the legislature specified the same grounds for sustaining an objection or a complaint.[61] Grounds for an objection are stated in Section 20.4(1) while grounds for a complaint about an ISO rule that is in effect are stated in Section 25(1)(b). The grounds for an objection and a complaint found in the 2003/07 *Electric Utilities Act* differ from grounds for a complaint under Section 25 of the 2003 *Electric Utilities Act.* This was discussed above in section 4.1 of this decision.

110. Section 25 of the 2003/07 *Electric Utilities Act* provides in relevant part as follows:

> **Complaints to the Commission**
>
> **25(1)** A market participant may make a written complaint to the Commission
>
> (a) about an ISO fee, or
>
> (b) about an ISO rule that is in effect, on one or more of the following grounds:
>
> (i) that the ISO rule is technically deficient;
>
> (ii) that the ISO rule does not support the fair, efficient and openly competitive operation of the market;
>
> (iii) that the ISO rule is not in the public interest.
>
> …

61 There is one additional ground upon which an objection can be based that is not also available in the case of a complaint about a rule that is in effect. Under Section 20.4(1)(a), an objection can be made based on the failure of the ISO to follow procedures and processes for rulemaking required of the ISO by a Commission rule.

(2) A complaint about an ISO fee must be made within 60 days after the day on which the market participant receives notice of the fee.

…

(4) The Commission may decline to hold a hearing or other proceeding if, in the opinion of the Commission,

(a) the complaint is frivolous, vexatious, trivial or otherwise does not warrant a hearing or other proceeding, or

(b) the complaint or the substance of it has been referred to, should be referred to, or is the subject of investigation by, the Market Surveillance Administrator.

(4.1) Where a market participant files a complaint, the market participant has the onus of proving

(a) that the ISO rule is technically deficient,

(b) that the ISO rule does not support the fair, efficient and openly competitive operation of the market, or

(c) that the ISO rule is not in the public interest.

…

(4.2) The Commission must decline to hold a hearing or other proceeding if, in the opinion of the Commission, the complaint or the substance of it relates to the Independent System Operator's compliance with the Commission rules made under section 20.9 in making the ISO rule.

(5) Unless the Commission otherwise orders, a complaint under this section does not relieve the person making the complaint from the obligation

(a) to pay an ISO fee pending a decision of the Commission, or

(b) to comply with an ISO order or ISO rule pending a decision of the Commission.

(6) The Commission may, after hearing a complaint, by order,

(a) determine the justness and reasonableness of the ISO fee and confirm, change or revoke the fee,

(b) direct the Independent System Operator to reimburse a market participant any fee paid to the Independent System Operator,

(c) confirm the ISO rule,

(d) disallow the ISO rule, or

(e) direct the Independent System Operator to change the ISO rule or a provision of the ISO rule.

(7) The Independent System Operator must file with the Commission an ISO rule that is changed pursuant to an order under subsection (6)(e).

(8) The Commission must publish notice of the filing of an ISO rule under subsection (7) as soon as possible and not later than 5 days after the day of filing.

(9) A change to an ISO rule filed under subsection (7) comes into effect on the latest of

(a) the day on which it is filed,

(b) the day specified in the ISO rule, and

(c) the day otherwise ordered by the Commission.

111. Section 25(1)(b) enumerates the grounds upon which a complaint against an ISO rule that is in effect may be filed. Section 25(4.1) meanwhile, provides that the complainant bears the onus of proving that an ISO rule fails to meet one or more of these grounds of complaint.

112. Unlike when a market participant files a notice of objection to an ISO rule, the Commission, pursuant to Section 25(4)(a), is expressly authorized to decline to hold a hearing or other proceeding on the complaint if, in the opinion of the Commission, “the complaint is frivolous, vexatious, trivial or otherwise does not warrant a hearing or other proceeding.” The wording of Section 25(4) of the 2003 *Electric Utilities Act* was very similar, except that it applied both to complaints about proposed ISO rules and ISO rules already in effect. In the 2003/07 *Electric Utilities Act* the grounds are stated in two places, once for objections and once for complaints.

113. Section 25(5) is essentially identical in the 2003 and 2003/07 *Electric Utilities Act*. It provides that a complainant has the obligation to pay an ISO fee or comply with an ISO order or rule pending a decision of the Board (or Commission) unless the Board (or Commission) orders otherwise.

114. Other similarities between the 2003 *Electric Utilities Act* and the 2003/07 *Electric Utilities Act* include the following. Section 21(3) of the 2003 *Electric Utilities Act* was left unchanged by the 2007 amendments to the *Electric Utilities Act*. It requires market participants who have been charged a fee by the ISO to pay that fee. As noted above, filing a complaint with the Commission or Board about an ISO fee does not relieve the complainant of the obligation to pay the fee pending a decision of the Commission or Board unless the Commission or Board orders otherwise (Section 25(5)(a) in both Acts). The content of Section 25(6)(d) of the 2003 *Electric Utilities Act* became 25(e) and was otherwise untouched by the 2007 amendments. It authorizes the Commission or Board to reimburse a market participant any ISO fee it paid if the fee is subsequently found not to have been just and reasonable (as required by Section 21(2) under both Acts).

115. The 2003/07 *Electric Utilities Act* also eliminated the provisions in sections 22 to 24 of the 2003 *Electric Utilities Act* relating to the enforcement of ISO compliance orders and orders imposing administrative penalties on market participants. Under the 2003 *Electric Utilities Act*, these provisions served to restrict the ability of the ISO and the courts to enforce compliance orders and orders imposing administrative penalties upon market participants pending decisions of the Board with respect to complaints made against those very same orders. Under Section 22(1) of the 2003/07 *Electric Utilities Act*, if a market participant fails to pay an ISO fee the AESO may refer the matter to the Commission. If the Commission, in turn, is satisfied that a market participant has failed to pay an ISO fee, it may order the market participant to pay the fee

and may impose an administrative penalty on the market participant under Section 63 of the *Alberta Utilities Commission Act*. Like the 2003 *Electric Utilities Act*, there is no express provision in the rulemaking sections of the 2003/07 *Electric Utilities Act* that deals with reimbursement or other settlement in the event that a rule-based tariffed charge is found unlawful or non-compliant.

116. Section 25(9) of the 2003/07 *Electric Utilities Act*, by comparison, has no counterpart in the 2003 *Electric Utilities Act*. It prohibits the retroactive application or operation of an ISO rule that (1) was in effect when it became the subject of a complaint; (2) the Commission, after a hearing, has ordered the ISO to change; and (3) the AESO has changed and filed with the Commission under Section 25(7).

117. In the event of a successful objection (Section 20.5(1)) or a successful complaint (Section 25(6)) under the 2003/07 *Electric Utilities Act*, the Commission may confirm the ISO rule, disallow the ISO rule or direct the Independent System Operator to change the ISO rule or a provision of the ISO rule.

4.2.4 2003/07 *Electric Utilities Act* ratemaking provisions

118. The general ratemaking provisions of the 2003/07 *Electric Utilities Act* are essentially unchanged relative to those in the 2003 *Electric Utilities Act*. However, new provisions were added that clarified the Commission's role in reviewing certain costs included in an AESO tariff application. The Commission reviewed the ISO tariff framework provisions, including line loss charges, in Decision 2014-242 as follows:

> 32. Section 119(4) of the *Electric Utilities Act*, SA 2003, c. E-5.1, requires the AESO to prepare a tariff and to apply to the Commission for approval of this tariff. The tariff is composed of two elements: (1) costs and expenses and (2) the proposed allocation of costs and expenses to rate classes (rate design).
>
> 33. Generally, there are four principal categories of costs and expenses incurred by the AESO that are included in its tariff: (1) the AESO's own administrative costs; (2) ancillary services costs; (3) transmission line losses; and (4) costs related to transmission wires (payable under a TFO tariff). The provisions of the *Electric Utilities Act*, and the *Transmission Regulation*, AR 86/2007, provide specific direction to the Commission regarding the extent to which the Commission may assess these costs and expenses.
>
> 34. The AESO's own administrative costs are defined in Section 1(1)(g) of the *Transmission Regulation* to include: (1) the transmission-related costs and expenses of the AESO respecting the administration, operation and management of the AESO; (2) the transmission-related costs and expenses of the AESO respecting reliability standards and reliability management systems; and (3) the transmission-related costs and expenses required to be paid by the AESO except for the costs of providing ancillary services, costs of transmission line losses and amounts payable under TFO tariffs.
>
> 35. The AESO's own administrative costs are approved by the AESO's board, defined in the *Transmission Regulation* in Section 1(f) as "ISO members." Section 3(1) of the *Transmission Regulation* requires the AESO to engage in consultation with those market participants who are likely to be directly affected by the approval by the AESO board of its own administrative costs. Consequently, Section 46 (1) of the *Transmission Regulation* limits the Commission's review of the AESO's own administrative costs to those costs which an interested party has argued are unreasonable. Moreover, the onus is on the interested party, not the AESO, to

> satisfy the Commission that the AESO's own administrative costs are not reasonable. Absent this, the provisions of the *Transmission Regulation* require the Commission to consider the AESO's own administrative costs to be prudent.
>
> 36. Similarly, the AESO board also approves the costs for ancillary services and line losses. Consequently, Section 3 (1) of the *Transmission Regulation* also requires the AESO to consult with market participants directly affected by these costs. However, there is no equivalent provision to Section 46 (1) of the *Transmission Regulation* that provides an interested party with the ability to argue the reasonableness of these costs before the Commission. Instead, Section 20 of the *Electric Utilities Act* and sections 15, 17, 33 and 34 of the *Transmission Regulation* authorize and, in some instances, direct the AESO to establish rules related to the calculation and recovery of ancillary service costs and costs for line losses. Consequently, where ISO rules are proposed or created for the calculation and recovery of ancillary service costs or the costs for line losses, the Commission's oversight of these costs is addressed through the objection and complaint provisions found in sections 20 and 25 of the *Electric Utilities Act*, respectively.
>
> 37. The Commission tests the amounts payable under the TFO tariffs in separate transmission tariff proceedings for each of the transmission utilities that provide transmission services to the AESO. Therefore, these costs are not tested in the AESO tariff.[62]

119. While new provisions dealing with line loss costs and tariffs were added to the 2003/07 *Electric Utilities Act*, they did not change the circumstances under which the Commission was required to consider tariffs in the 2003 *Electric Utilities Act*. In both cases the terms of the legislation do not allow the Board or Commission to examine the line loss charge component of the ISO tariff unless it has received a complaint about the Line Loss Rule.

4.2.5 Interpretations of the statutory schemes

4.2.5.1 Negative disallowance, ISO rules and the ISO tariff

120. The overall statutory scheme of the 2003 *Electric Utilities Act* and the 2003/07 *Electric Utilities Act* cannot be fully understood without considering the linkages between the rulemaking and ratemaking provisions of the Acts in a case such as this, in which the rule in question is designed to determine line loss charges and credits in the ISO tariff.

121. The relationship between the Line Loss Rule, line loss factors produced by that rule, tariffed Supply Transmission Service (Rate STS) and charges under Rate STS is described in the ISO tariff as follows: "2(1) The charge under Rate STS in a settlement period will be the losses charge calculated as the sum, over all hours in the settlement period, of metered energy in the hour multiplied by pool price multiplied by a loss factor for the facility, where the loss factor is determined in accordance with ISO rule 9.2 and is available to market participants in the loss factors section of the ISO website." Similar provisions exist in the ISO tariff with respect to the rates for Rate DOS (Demand Opportunity Service), Rate XOS (Export Opportunity Service), and Rate IOS (Import Opportunity Service)."[63] This relationship between the Line Loss Rule and the ISO tariff has remained in place since January 1, 2006. Indeed, even though the Line Loss Rule is no longer ISO rule 9.2, the old number of the rule remains in the ISO tariff today.

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[62] AUC Decision 2014-242, August 21, 2014, pages 7 and 8 paragraphs 32 to 37.

[63] See, exhibit 548.01, ATCO Power Argument, page 5, paragraph 19.

122. All parties to this proceeding agree that the rulemaking provisions of the 2003 *Electric Utilities Act* inherently constitute a negative disallowance scheme,[64] the hallmark of which is that rules take effect without prior Board review or approval.

123. The difference between negative disallowance schemes and positive approval schemes was discussed in *Bell Canada* v. *Canada (Canadian Radio-Television and Telecommunications Commission),* [1989] 1 S.C.R. 1722 (*Bell Canada*) as follows:

> Much was said in argument about the difference between positive approval schemes and negative disallowance schemes with respect to the power to act retrospectively. The first category includes schemes which provide that the administrative agency is the only body having statutory authority to approve or fix tolls payable to utility companies; these schemes generally stipulate that tolls shall be "just and reasonable" and that the administrative agency has the power to review these tolls on a *proprio motu* basis or upon application by an interested party. The second category includes schemes which grant utility companies the right to fix tolls as they wish but also grant users the right to complain before an administrative agency which has the power to vary those tolls if it finds that they are not "just and reasonable".[65]

124. Although the Alberta Court of Appeal in its decision on the Milner appeal regarding the Board's decision not to hear the Milner complaint[66] did not use the term "negative disallowance scheme" to describe the ISO rulemaking process, it is clear from the court's decision that this is what it was describing when it recognized the ISO's authority to develop and implement rules and then stated that the "AESO's authority is limited by the complaint process."[67] It is also clear that a negative disallowance scheme is what the legislature had intended to create when it enacted the rulemaking provisions of the 2003 *Electric Utilities Act*. In the case of ISO rules, the rules go into effect and may be changed or revoked later on complaint. There is no provision by which the Board can stop a rule from going into effect before a complaint has been heard.[68]

125. Several parties argue, however, that unlike the rulemaking provisions of the 2003 *Electric Utilities Act*, the ratemaking provisions of the 2003 *Electric Utilities Act* applicable to the ISO tariff constitute a positive approval scheme. According to these parties, the Commission, in accordance with sections 121 and 124, approves line loss charges included in the ISO tariff on a final basis after determining them to be just and reasonable or otherwise in accord with the 2003

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[64] Some parties discussed the negative disallowance scheme under both the 2003 and the 2003/07 *Electric Utilities Act* and others discussed it only in the context of the 2003/07 *Electric Utilities Act.* The Commission considers the discussion about negative disallowance to apply to the provisions of both versions of the *Electric Utilities Act.*

[65] *Bell Canada* at page 1758.

[66] *Milner*

[67] *Milner*, paragraph 52

[68] However, under the 2003/07 *Electric Utilities Act*, except where Section 20.6 is used by the ISO to introduce expedited rules, the ISO rulemaking provisions are transformed from a negative disallowance scheme to a form of positive approval scheme when an objection is filed. This transformation occurs because, once an objection is made, the ISO rule cannot take effect until the Commission has first examined it and satisfied itself that the rule complies with the governing legislation and regulations. This feature is the hallmark of a positive approval scheme. What makes this positive approval scheme unconventional, however, is that pursuant to Section 20.4(3) of the 2003/07 *Electric Utilities Act*, the complainant bears the burden of establishing that the impugned ISO rule is non-complaint. Ordinarily, the applicant (or party seeking to have a tariff or rule approved) would bear the onus of establishing that the rule (or tariff) meets the requirements of the legislation and applicable regulations.

Electric Utilities Act and applicable regulations. The Commission notes, however, that sections 121 and 124 of the 2003 *Electric Utilities Act* are affected by the statutory presumption in Part 2, Division 2 of the 2003 *Electric Utilities Act* that ISO rules (including rules that determine ISO tariff rates) are presumed to be just and reasonable unless and until determined to be otherwise upon complaint under Section 25 of the 2003 *Electric Utilities Act*. This is the very nature of a negative disallowance scheme: rules are presumed to be compliant with the statutory test unless and until successfully challenged on complaint.

126. The AESO, in its reply argument in this proceeding, described the nature of the rulemaking and ratemaking provisions of the 2003/07 *Electric Utilities Act* in the following terms:[69]

> [T]he implementation of the line loss rule is akin to a negative disallowance scheme. In other words, the EUA provides that the AESO is permitted to implement the line loss rule subject to a market participant's objection or complaint, which would only then trigger a review into whether the line loss rule complies with the applicable legislation. Prior to a complaint about the line loss rule being decided by the Commission, the line loss rule remains in effect and continues to be the basis upon which line loss charges and credits are determined unless the Commission orders otherwise.
>
> The approval of the AESO's tariff, on the other hand, is a positive approval scheme. In other words, section 125 of the EUA requires the AESO's tariff to be approved by the Commission before it is put into effect.[70]

127. The Commission is not persuaded by the AESO's argument that the ratemaking process applicable to rates for line losses in the ISO tariff can be described as a positive approval scheme. This is because the Board has no avenue through which it can actually test the justness and reasonableness of those line loss charges before approving them in the ISO tariff, unless and until a complaint against the Line Loss Rule is made under the rulemaking provisions of the 2003 *Electric Utilities Act*. The AESO's submissions on this matter in this proceeding further support this finding:

> It is clear that the AESO could not have put into effect its tariff until it was approved by the Commission pursuant to section 125 of the EUA. However, the AESO recognizes that, in accordance with the EUA, the Commission did not turn its mind to whether the line loss rule complied with the EUA and the 2004 TReg in the AESO's tariff proceedings. It was not until Milner complained about the line loss rule pursuant to section 25 of the EUA that the Commission considered whether it complied with the EUA and the 2004 TReg in a separate proceeding.
>
> In other words, in accordance with the EUA, the Commission did not consider the reasonableness of the line loss rule or whether it complied with the EUA or 2004 TReg in the AESO's tariff proceedings, even though the Commission did approve Rate STS, which was included in the AESO's tariffs.[71]

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69 Although the AESO was referring to the 2003/07 *Electric Utilities Act* here, its views on this point apply equally to both versions of the *Electric Utilities Act*.

70 Exhibit 555.01, AESO Reply Argument, October 22, 2014, pages 3 and 4.

71 Exhibit 547.01, AESO Argument, September 24, 2014, page 10.

128. While the AESO has not stated in this proceeding that the Commission is without authority to test the justness and reasonableness of the line loss charges in the ISO tariff, the Commission understands the AESO to be saying that ("in accordance with the EUA") the Commission cannot consider in a tariff proceeding whether the manner in which the line loss charges themselves are calculated or determined complies with applicable legislation and regulations. Instead, any examination by the Commission of the compliance with the legislation and regulations of the Line Loss Rule and the line loss factors from which line loss charges in the ISO tariff are derived should only be conducted if a complaint has been filed about the Line Loss Rule, and then only pursuant to the provisions of Section 25 of the *Electric Utilities Act*. According to the AESO, in this proceeding:

> [T]he line loss rule and the line loss factors produced by it are not tariffs, rates or charges. Rather, the line loss rule is an ISO rule in accordance with which line loss factors are calculated. Those line loss factors are then used in the calculation of a rate – more specifically, Rate STS – which is included in the AESO's tariff.
>
> The AESO submits that the legal significance of this interpretation is that the line loss rule and the line loss factors produced by it have not been, nor should they be, considered by the Commission in the AESO's tariff proceedings. Instead, any consideration of the line loss rule and the line loss factors produced by it has occurred, and should continue to occur, pursuant to section 25 of the EUA.[72]

129. The Commission agrees that the ratemaking provisions of the 2003 *Electric Utilities Act* generally describe a positive approval scheme. However, where the rates to be approved are determined through an ISO rule, there is no positive approval scheme. The Line Loss Rule's sole purpose is to recover and allocate the costs of transmission line losses from and amongst generating units in accordance with the requirements of the legislation, including the fair efficient and openly competitive (FEOC) principles and the very specific provisions of the 2004 (and 2007) *Transmission Regulation*.[73]

130. The Board was and the Commission continues to be unable to examine the justness and reasonableness of the Line Loss Rule and the line loss charge components of the ISO tariff it produces unless there is an ISO rule complaint. This legislative scheme for ISO rule-based tariffs means that the line loss charge components of the ISO tariff are subject to a negative disallowance scheme, not a positive approval scheme.[74]

131. Where a negative disallowance scheme is in effect, the legislation creates a presumption that the rule and any charges it produces are just and reasonable or otherwise consistent with the legislation from the outset. This legislative presumption, applies to the entire rule. Therefore, the line loss charges produced by the line loss factor calculation methodology, which forms the very heart of the rule, must also be presumed just and reasonable from the moment the AESO applies to the Commission for approval of its entire tariff, including the line loss charges and credits

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72 Exhibit 547.01, AESO Argument, September 24, 2014, page 3.

73 ISO rule 9.2 itself describes the purpose of the Line Loss Rule as follows: "The purpose of this rule is to describe the means by which the ISO determines annual loss factors to provide for the reasonable cost recovery of transmission line losses in accordance with the requirements of the [*Transmission Regulation*]."

74 This is not the only portion of the ISO tariff that is the subject of a negative disallowance scheme. See paragraph 118 in this decision which explains that the AESO's own costs of operation must be accepted by the Commission for inclusion in the ISO tariff unless a complaint is made about that portion of the tariff.

embedded within it.[75] Any attempt by the Board to circumvent this clear legislative division of powers between the AESO and itself as concerns the making of and coming into effect of ISO rules and the approval of ISO tariff rates based on ISO rules would amount to the Board (or Commission) doing indirectly that which the scheme of the 2003 *Electric Utilities Act* precludes it from doing directly – examining an ISO rule when no complaint has been filed about that rule.

132. Indeed, this is precisely the approach taken by the EUB when it refused to consider Milner's complaint in the AESO 2005/2006 tariff proceeding and left that determination to be made by it in the complaint process. Later on April 5, 2006, the Board considered a review and variance application on its refusal to hear the complaint in the tariff proceeding and, in its decision, referred to the fact that it had reviewed and dismissed the complaint. It also said that the AESO was free to implement the rule (and therefore the tariff) on January 1, 2006. The negative disallowance scheme for the ISO rule and resulting tariff changes, included in the 2003 *Electric Utilities Act*, has since been made even more clear in the 2003/07 *Electric Utilities Act*. This is described in the Commission's review of the regulatory framework relating to the Line Loss Rule and the ISO tariff in Decision 2014-242, described above.

133. The Commission also made the following finding at paragraphs 65 to 67 of Decision 2014-242:

> 65. The AESO board has both the responsibility and the authority under the *Electric Utilities Act* and the *Transmission Regulation* to approve the quantum of ancillary services costs, line loss costs and the AESO's own costs. The Commission's role in reviewing these costs in a tariff proceeding is limited.
>
> 66. As explained in Section 3.1 of this decision, the legislation establishes a scheme in which costs approved by the AESO board are generally not reviewed by the Commission in tariff proceedings (other than the AESO's own administrative costs on a limited basis). The rationale for this limited review in tariff proceedings is premised on two factors: (1) that market participants will have an opportunity to engage in consultation with the AESO regarding these costs and (2) that, for certain of these costs, the AESO has been directed to create a rule, in which case, market participants have an opportunity to bring forward objections or complaints to the Commission regarding the rule. Additionally, Section 26 of the *Electric Utilities Act* enables any person to make a complaint to the Commission regarding the conduct of the AESO.
>
> 67. Section 121 of the *Electric Utilities Act* requires the Commission, when considering whether to approve a tariff application, to ensure, *inter alia,* that the tariff is just and reasonable and that the tariff is not unduly preferential, arbitrarily or unjustly discriminatory or inconsistent with or in contravention of any enactment or law. Consequently, the Commission considers that in approving an AESO tariff, it must be satisfied that the AESO has complied with the legislative requirements imposed on it to consult as directed by the *Transmission Regulation.*[76]

134. Limiting the review of the line loss charge components of the ISO tariff to the satisfactory completion of a consultation requirement does not constitute a positive approval scheme for the actual tariffed rates. To hold otherwise, would result in no oversight either in the

[75] This presumption is evidenced by sections 16, 21(2), and 25(6) of the 2003 *Electric Utilities Act.*
[76] AUC Decision 2014-242, August 21, 2014, pages 13 and 14, paragraphs 65 to 67.

first instance or on complaint, of the actual tariffed line loss charges. Therefore, the Commission finds that whether one proceeds under the 2003 *Electric Utilities Act* or the 2003/07 *Electric Utilities Act*, the ISO rule complaint provisions for the implementation and review of the Line Loss Rule constitute a negative disallowance scheme. The Commission also finds that the resulting line loss charge components of the ISO tariff is subject to a negative disallowance scheme under both the 2003 and 2003/07 *Electric Utilities Acts*. Therefore, because the Line Loss Rule may be overturned or modified as a result of a complaint, the line loss charges flowing from that rule must necessarily be subject to a negative disallowance scheme.

4.2.5.2 **Safeguards**

135. Under the 2003 *Electric Utilities Act*, the Board could decline to hear an ISO rule complaint, whether filed before or after a rule was in effect. In the 2003/07 *Electric Utilities Act* the Commission cannot decline to hear an objection. It must hear the objection. A non-expedited ISO rule cannot go into effect until the objection has been dealt with by the Commission. In the case of a complaint under the 2003/07 *Electric Utilities Act* about an ISO rule that is in effect, the Commission may decline to hear the complaint.

136. This ability to stop the implementation of a non-expedited rule by objecting to it is a significantly stronger safeguard than the inability of the ISO to enforce, in the courts, an ISO order to comply with a rule while it is subject to complaint coupled with the power to revoke a rule after a successful complaint. But with this stronger safeguard comes a limitation on remedies that is not expressed in the 2003 *Electric Utilities Act* complaint provisions. Section 25(9) of the 2003/07 *Electric Utilities Act* stipulates that an ISO rule that has been changed pursuant to a direction by the Commission after hearing a complaint cannot “come into effect” retroactively.

137. While Section 25(9) creates incentives for those who benefit from an impugned rule to prolong the complaint review process, the complainant is not without safeguards. One safeguard is the ability of the complainant to stop implementation of the rule in the first place by objecting to it. The other is for a complainant to file a complaint and ask the Commission to relieve the complainant from the obligation to comply with the rule. As noted above, in the case of the Line Loss Rule, it would be difficult to relieve a complainant from complying since all generators’ charges and credits must balance.[77] In the Commission’s view, it is the ability to object to and thereby stop implementation of a rule under Section 20.4 before it goes into effect that acts as a counterbalancing safeguard to the perverse incentives and effects otherwise created by Section 25(9).

138. The Commission has considered the effect of Section 20.1 of the 2003/07 *Electric Utilities Act*. That section states that the objection provisions in sections 20.2 to 20.5 do not apply to an ISO rule that was made prior to the coming into force of those sections. As the Commission has noted earlier in this decision, Milner exercised its right to file its complaint about the Line Loss Rule after it was made but before the Line Loss Rule was put into effect.

139. Section 25(1)(b) of the 2003/07 *Electric Utilities Act*, by its express terms, applies only to complaints about an ISO rule “that is in effect.” In the context of the safeguards allowing for

[77] In the case of a new entrant who did not have an opportunity to object to the rule, the complaint process and the limitation on the remedy seems acceptable because the new entrant can simply choose not to enter the market.

objections to stop a rule from going into effect and complaints being made only about ISO rules that are in effect, a complaint about an ISO rule that is in effect must mean that the rule must be in effect when the complaint is made. Since Milner's original complaint was directed at an ISO rule that had been made but was not yet in effect, Section 25 of the 2003/07 *Electric Utilities Act*, by its express terms, cannot apply to Milner's complaint. There is nothing in the 2003/07 *Electric Utilities Act* to suggest that a complaint made about a rule that was not yet in effect can be transformed into a complaint about a rule that is in effect at the time the complaint was made simply by the enactment of the 2003/07 *Electric Utilities Act.*

140. For this reason and others discussed in section 4.4.2 (where the Commission discusses the overlap of the 2003 and 2003/07 *Electric Utilities Act*), the Commission finds that the Milner complaint and any remedies available are to be determined under the provisions of the 2003 *Electric Utilities Act.*

4.2.5.3 Tariff-based relief for unlawful line loss charges

141. AltaGas has argued in this proceeding that the Commission has only dealt with the Milner complaint against the Line Loss Rule and that the Milner complaint was not a complaint about the line loss charge component of the ISO tariff. AltaGas, in argument states:[78]

- An ISO rule is a separate and distinct concept from an ISO tariff, and the ISO tariffs at issue in this case do not incorporate the line loss rules. This distinction reflects the fact that rates are charged and collected, not under a line loss rule but under the ISO tariff. … The Commission has jurisdiction to change the charges and credits for transmission line losses from the date of its eventual decision on the Complaint, or as soon thereafter as a new ISO rule for calculating transmission line losses can be put in place. Its powers to respond to the Complaint do not include the authority to make any retroactive alteration to the Rule, or any alteration at all to an ISO tariff. (paragraph 17)

- Neither the Complaint nor the Court's direction refers to any ISO tariff, or suggests that any ISO tariff is at issue in any of the proceedings. (paragraph 39)

- ISO rules are clearly distinct from the ISO tariff, as evidenced by their completely separate treatment under the *EUA* and the regulatory scheme. ISO rules are technical details and guidance documents enacted by the AESO; ISO tariffs are rate-setting documents that must be approved by the Commission before they can enter into effect. Although ISO tariffs can and do reference ISO rules, the two concepts are legally and functionally distinct. (paragraph 40)

- Nothing in ss. 25 or 26 permits the Commission to make directions in respect of matters beyond the ISO rule or the ISO conduct complained of, respectively. The clear language of ss. 25 and 26 provides that the Commission lacks jurisdiction to make directions in respect of any matter that does not fall within the Complaint. In particular, neither s. 25 nor s. 26 contemplates any alterations to an ISO tariff, or to a Commission decision approving an ISO tariff. ISO tariffs are subject to a completely different approval process, and must be approved by the Commission before they may take effect. (paragraph 44)

- If any ISO tariffs were disputed by reason of their reference to the Rule, it was open to Milner or any other allegedly aggrieved persons to challenge or appeal those tariffs. Those persons chose not to do so, and cannot now attempt to attack the tariff by means of the Complaint,

[78] Exhibit 544.02, AltaGas Argument, September 24, 2014.

which pertains exclusively to the Rule and for which the available remedies are limited to the Rule. (paragraph 45)

- As discussed above, the AESO has elected under s.30(4) *EUA* to collect its line loss charges through its tariff. No ISO tariff is at issue in the Complaint, which concerns only the Rule. The Commission's jurisdiction under ss.25 and 26 *EUA* is limited to the Rule and does not permit the Commission to alter an ISO tariff. Moreover, the Commission's powers to change or disallow the Rule may only be exercised with prospective effect, and cannot impact past tariffs. (paragraph 62)

- In the Complaint, which provides the jurisdictional framework for this proceeding, Milner chose only to ask the Board to examine the Rule. Neither Milner nor any other party should now be allowed -- with benefit of hindsight, in circumvention of the procedure established by the Legislature, and to the prejudice of all market participants – to attack past ISO tariffs. (paragraph 64)

- The bottom line is that the Commission is without jurisdiction to use its rate-making powers to award financial compensation to any party for losses suffered as a result of the Rule's non-compliance. This does not necessarily entail injustice to Milner and other allegedly aggrieved parties: all it means is that the Commission is not, under these circumstances, an appropriate forum for market participants to seek restitution of any payments. (paragraph 74)

142. The Commission does not agree with AltaGas. Upon review of the Milner complaint, it is clear that the complaint was made because of the monetary effects the line loss charge components produced by the Line Loss Rule and incorporated into the ISO tariff would have on Milner. Indeed, TransAlta, acknowledges at paragraph 39 of its written argument "that Milner's concern is the financial implications of the application of the ISO Rule and resulting Loss Factor that would be used to calculate Rate STS, which would in turn be collected through the ISO tariff." Further, Milner's complaint was filed in the AESO's 2005-2006 General Tariff Application proceeding.

143. In the Commission's view, to complain about the Line Loss Rule is to complain about the line loss charge components of the ISO tariff. The line loss charge components of the ISO tariff have been unjust, unreasonable, unduly preferential, and arbitrarily or unjustly discriminatory and inconsistent with Alberta legislation since January 1, 2006 because they are produced by the Line Loss Rule that has been unjust, unreasonable, unduly preferential, and arbitrarily or unjustly discriminatory and inconsistent with or in contravention of the *Electric Utilities Act* and the *Transmission Regulation* since January 1, 2006.

144. Section 25 of the *Electric Utilities Act* allows for complaints to be made with respect to ISO fees. Section 25(6)(d) of the 2003 *Electric Utilities Act* and Section 25(6)(b) of the 2003/07 *Electric Utilities Act* also allow for reimbursement of improperly charged fees. Section 25(6)(e) of the 2003 *Electric Utilities Act* also provides for reimbursement of improperly assessed ISO administrative penalties. The 2003/07 *Electric Utilities Act* does not deal with reimbursement of improperly assessed administrative penalties, which under that Act can only be imposed by the Commission and may be appealed.

145. Some of the respondents argue, based on the implied exclusion rule, that because the *Electric Utilities Act* specifically allows for reimbursement in the case of unlawful fees (and in

the 2003 *Electric Utilities Act*, administrative penalties) it does not allow for reimbursement or other settlement when a rule-based tariff is found to be unlawful.[79] They argue that the party complaining about having to pay an unlawful ISO rule-based tariff is entitled only to have the rule changed prospectively and has no way of being reimbursed for any improper charges imposed through the unlawful rule and tariff produced by it. According to these parties, if the legislature had chosen to allow for monetary remedies for improper rule-based tariffed charges, it would have said so explicitly. The Commission does not agree with this interpretation.

146. As noted above in the discussion of the rule making provisions of the *2003 Electric Utilities Act* and the 2003/07 *Electric Utilities Act*, there is no express provision in the rulemaking sections of either Act that deals with reimbursement in the event that a rule-based tariffed charge is found unlawful or non-compliant. In the Commission's view this is because Section 25 deals with complaints about ISO rules and remedies in the event of a successful complaint. It does not deal with the ISO tariff which is the vehicle through which line loss charges are paid. The tariff provisions of the legislation include all of the remedies available in the legislation and under the applicable common law, including remedies allowing for retroactive and retrospective ratemaking, necessary to remedy the imposition of unlawful tariffs produced by an unlawful ISO rule. Therefore there is no reason to include specific tariff-based monetary remedies in the rulemaking provisions of the legislation.

4.3 Jurisprudence on retroactive ratemaking

147. Parties to this proceeding referred to the considerable jurisprudence dealing with the Commission's ratemaking powers and duties. The Commission has undertaken an extensive review of the jurisprudence in order to assist it in determining whether its powers include the ability to grant tariff-based relief where the line loss charges in the ISO tariff have been found to be unlawful.

148. One of the leading cases with respect to the ratemaking powers of regulatory tribunals is the decision of the Supreme Court of Canada in *Stores Block*. In that decision, the majority of the court enunciated the well-established administrative law principle that:

> Administrative tribunals or agencies are statutory creations: they cannot exceed the powers that were granted to them by their enabling statute; they must "adhere to the confines of their statutory authority or 'jurisdiction'[; and t]hey cannot trespass in areas where the legislature has not assigned them authority": Mullan, at pp. 9-10 (see also S. Blake, *Administrative Law in Canada* (3rd ed. 2001), at pp. 183-84).[80]
>
> But more specifically in the area of administrative law, tribunals and boards obtain their jurisdiction over matters from two sources: (1) express grants of jurisdiction under various statutes (explicit powers); and (2) the common law, by application of the doctrine of jurisdiction by necessary implication (implicit powers) (see also D. M. Brown, *Energy Regulation in Ontario* (loose-leaf ed.), at p. 2-15).[81]

79 Exhibit 556.02, AltaGas Reply Argument, October 22, 2014, pages 18-19, paragraphs 42-43; and exhibit 554.01, TCE Reply Argument, October 22, 2014, page 12, paragraph 44.
80 *Stores Block,* paragraph 35.
81 *Stores Block,* paragraph 38.

149. Accordingly, if the Commission possesses the necessary authority to retroactively alter or, more accurately, to alter with retrospective effect, the unlawful rates in the ISO tariff, that authority must be found in the Commission's enabling statutes and/or in the common law interpreting its powers under those statutes. All parties in this proceeding agree. Where they differ is in their interpretation of the applicable statutes and common law.

150. In addition to relying on Section 25(9) of the 2003/07 *Electric Utilities Act* as an absolute bar to retroactive rulemaking in the present proceeding, the respondents rely on the common law principle prohibiting retroactive ratemaking for the proposition that the only remedy available to Milner is a change in the ISO tariff on a strictly prospective basis.[82] Several of these parties pointed to the *Stores Block* decision for the following statement of the law in Canada:

> It is well established throughout the various provinces that utilities boards do not have the authority to retroactively change rates (*Northwestern 1979*, at p. 691; *Re Coseka Resources Ltd. and Saratoga Processing Co.,* 1981 ABCA 180, 126 D.L.R. (3d) 705 (Alta. C.A.), at p. 715, leave to appeal refused, [1981] 2 S.C.R. vii; *Re Dow Chemical Canada Inc.* (C.A.), at pp. 734-35).[83]

151. Likewise, TransCanada Energy[84] and AltaGas,[85] in their written arguments in this proceeding, cited the following passage from *Sullivan on the Construction of Statutes* on the general rule against retroactive ratemaking:

> It is obvious that reaching into the past and declaring the law to be different from what it was is a serious violation of rule of law... the fundamental principle on which rule of law is built is advance knowledge of the law.

152. Several respondents also cited the Alberta Court of Appeal's decision in *Calgary (City) v Alberta (Energy and Utilities Board)*, 2010 ABCA 132 (*ATCO Gas*), in which the court affirmed that the general prohibition against retroactive ratemaking applies equally to retrospective ratemaking, as defined below:

> Retroactive ratemaking "establish[es] rates to replace or be substituted to those which were charged during that period": *Bell Canada v. Canada (Canadian Radio-Television and Telecommunications Commission)*, 1989 CanLII 67 (SCC), [1989] 1 S.C.R. 1722 at 1749 ("*Bell Canada 1989*"). Utility regulators cannot retroactively change rates (*Stores Block* at para. 71) because it creates a lack of certainty for utility consumers. If a regulator could retroactively change rates, consumers would never be assured of the finality of rates they paid for utility services.[86]
>
> Retrospective ratemaking, in contrast, imposes on the utility's current consumers shortfalls (or surpluses) incurred by previous generations of consumers. It is generally prohibited because it creates inequities or improper subsidizations as between past and present consumers (who may not be the same). "[T]oday's customers ought not to be held

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82 Several of the respondents, however, do accept that where the line loss charge components of the ISO tariff have been made interim, those charges may be revised with retrospective effect to the date they were made interim. This will be discussed at greater length below.
83 *Stores Block,* paragraph 71.
84 Exhibit 546.01, TCE Argument, September 24, 2014, page 7, paragraph 30.
85 Exhibit 544.02, AltaGas Argument, September 24, 2014, page 18, paragraph 49.
86 *ATCO Gas,* paragraph 47.

> responsible for expenses associated with services provided to yesterday's customers": Yvonne Penning, "*The 1986 Bell Rate Case: Can Economic Policy and Legal Formalism be Reconciled*" (1989), 47(2) U.T. Fac. L. Rev. 607 at 610. This is sometimes referred to as the problem of inter-generational equity[.][87]

153. The courts have recognized at least five exceptions to this ratemaking principle. They include: (1) adjustments to interim rates; (2) the use of deferral accounts to deal with differences between forecast and actual costs and revenues; (3) changes to rates as a result of the operation of a negative disallowance scheme; (4) changes to rates where affected parties knew or ought to have known that rates were subject to change (i.e., the "knowledge exception"); and (5) replacing rates in a tariff that has been determined to be a nullity.

154. The jurisprudence on the first two of these exceptions is both well established and not in dispute in this proceeding. This notwithstanding, the Commission finds that the legal principles governing a regulator's powers to revisit and revise rates set on an interim basis or made subject to deferral accounts provides important insights into regulatory ratemaking powers in circumstances where the knowledge exception or the exception for negative disallowance schemes applies. Accordingly, the Commission will review in some detail the common law governing these first two exceptions in so far as is relevant to the present proceeding. At the same time, the Commission recognizes that the common law with respect to the nullity exception has changed significantly in recent years, to the point where it remains unclear whether, or to what extent, an unlawful tariff might still be found to be a nullity. Consequently, the Commission will deal only very briefly with this potential exception to the rule against retroactive ratemaking. The remainder of the Commission's review of the jurisprudence on its authority to provide a remedy or relief to those parties harmed by the ISO's unlawful Line Loss Rule and tariff will focus on the knowledge exception and the exception for negative disallowance schemes.

4.3.1 Interim rates

155. It has been established law in Canada for many decades that where a regulatory tribunal approves rates on an interim basis, such rates may be revised by final order retroactive to the date of the interim order.[88]

156. One of the leading cases addressing the issue of a regulatory tribunal's authority to revise interim rates is *Bell Canada*. In that case, Bell Canada applied to the CRTC for rate relief on an urgent basis. The CRTC, based on the evidence before it, granted Bell an interim rate increase that, in its view, was sufficient to forestall a serious deterioration in that company's financial condition. Among the questions the Supreme Court addressed in its decision were the following. Could the CRTC (1) upon subsequent review of its initial decision, find the interim rates not to have been just and reasonable and, instead, (2) approve, on a final basis, lower rates effective to the date rates were first made interim and then (3) direct Bell to issue to its current customers a one-time credit or rebate equal to the excess revenues the Company had earned while rates were interim.

[87] *ATCO Gas,* paragraph 48.

[88] *Coseka Resources Limited* v. *Saratoga Process Company Limited*, 1981 ABCA 180, (*Coseka*) at paragraphs 32-36.

157. The Supreme Court made clear that what was at issue in this case was not retroactive ratemaking, but retrospective ratemaking. According to the court:

> [T]he effect of [the CRTC's] Decision 86-17 was not retroactive in nature since it does not seek to establish rates to replace or be substituted to those which were charged during that period. The one-time credit order is, however, retrospective in the sense that its purpose is to remedy the imposition of rates approved in the past and found in the final analysis to be excessive. Thus, the question before this Court is whether the appellant [the CRTC] has jurisdiction to make orders for the purpose of remedying the inappropriateness of rates which were approved by it in a previous interim decision.[89]

158. The first issue addressed by the Supreme Court was the extent of the CRTC's statutory authority to review and revise interim rates. In the circumstances of the *Bell Canada* case, the governing legislation explicitly contemplated the issuance of interim orders by the CRTC. However, the legislation did not explicitly authorize the CRTC to revisit and revise interim rates from the date they took effect. The Supreme Court considered this objection, and then dismissed it, holding that even where there is no express statutory authority granted to the regulator to revise interim rates from the date they take effect, that power must be taken to exist by the principle of necessary implication.

> The respondent [Bell Canada] argues that the power to revisit the period during which interim rates were in force cannot exist within the statutory scheme established by the *Railway Act* and the *National Transportation Act* because these statutes do not grant such a power explicitly, unlike s. 64 of the *National Energy Board Act*, R.S.C., 1985, c. N-7. The powers of any administrative tribunal must of course be stated in its enabling statute but they may also exist by necessary implication from the wording of the act, its structure and its purpose. Although courts must refrain from unduly broadening the powers of such regulatory authorities through judicial law-making, they must also avoid sterilizing these powers through overly technical interpretations of enabling statutes. I have found that, within the statutory scheme established by the *Railway Act* and the *National Transportation Act*, the power to make interim orders necessarily implies the power to revisit the period during which interim rates were in force. The fact that this power is provided explicitly in other statutes cannot modify this conclusion based as it is on the interpretation of these two statutes as a whole.[90]

159. In fact, the Supreme Court went further and cited with approval two decisions of the U.S. Supreme Court which found that even where a regulatory agency's enabling legislation provides it with no express authority to issue interim orders, much less to revisit and alter them with retroactive effect, such powers can be deemed to exist by virtue of the principle of necessary implication. (See, *United States v. Fulton*, 475 U.S. 657 (1986), at pp. 669-71; and *Trans Alaska Pipeline Rate Cases*, 436 U.S. 631 (1978), at pp. 654-56).[91]

160. The court, in making these findings, considered not only the scheme of the applicable legislation and the inherent nature of interim orders, but also looked at the rationale for making orders interim rather than final. Speaking for a unanimous seven-member panel of the Supreme Court, Gonthier J. held that:

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89 *Bell Canada*, page 1749.
90 *Bell Canada*, page 1756.
91 *Bell Canada*, page 1757.

> The very purpose of interim rates is to allay the prospect of financial instability which can be caused by the duration of proceedings before a regulatory tribunal. In fact, in this case, …[Bell] asked for and was granted interim rate increases on the basis of serious apprehended financial difficulties. The added flexibility provided by the power to make interim orders is meant to foster financial stability throughout the regulatory process. The power to revisit the period during which interim rates were in force is a necessary corollary of this power without which interim orders made in emergency situations may cause irreparable harm and subvert the fundamental purpose of ensuring that rates are just and reasonable.[92]
>
> A consideration of the nature of interim orders and the circumstances under which they are granted further explains and justifies their being, unlike final decisions, subject to retrospective review and remedial orders.[93]
>
> Traditionally, such interim rate orders dealing in an interlocutory manner with issues which remain to be decided in a final decision are granted for the purpose of relieving the applicant from the deleterious effects caused by the length of the proceedings. Such decisions are made in an expeditious manner on the basis of evidence which would often be insufficient for the purposes of the final decision. The fact that an order does not make any decision on the merits of an issue to be settled in a final decision and the fact that its purpose is to provide temporary relief against the deleterious effects of the duration of the proceedings are essential characteristics of an interim rate order.[94]

161. In other words, the court recognized that the very circumstances which call for interim, as opposed to final, rates also demand that those rates be revisited, when better information is available, in order to ensure that they were, in fact, just and reasonable throughout the interim period and will continue to be just and reasonable going forward, before being approved on a final basis.

162. In making this finding, the Supreme Court was careful to note that rates approved on an interim basis must be considered no less just and reasonable, at the time they are approved, than those approved on a final basis. The difference is that the evidence available to a regulator prior to approving rates on an interim basis may be (and typically would be) insufficient, and insufficiently tested by the rigours of a full hearing, for a determination of justness and reasonableness on a final basis. This, in turn, is why the power to subsequently revisit or reconsider interim rates, as of the date they came into effect, is essential before those rates can be approved on a final basis. If information becomes available to the regulator upon which it can conclude that the interim rates are no longer just and reasonable, then those rates must be revised before being given final approval.

> It is true… that all telephone rates approved by the [CRTC] must be just and reasonable whether these rates are approved by interim or final order… However, interim rates must be just and reasonable on the basis of the evidence filed by the applicant at the hearing or otherwise available for the interim decision. It would be useless to order a final hearing if the [CRTC] was bound by the evidence filed at the interim hearing. Furthermore, the interim rate increase was granted on the basis that the length of the proceedings could cause a serious deterioration in the financial condition of the respondent. Only once such an emergency situation was found to exist did the [CRTC] ask itself what rate increase would be just and

92 *Bell Canada*, page 1760-1761.
93 *Bell Canada*, page 1754.
94 *Bell Canada*, page 1754.

> reasonable on the basis of the available evidence and for the purpose of preventing such a financial deterioration. The inherent differences between a decision made on an interim basis and a decision made on a final basis clearly justify the power to revisit the period during which interim rates were in force.[95]

163. The court elaborated further on this distinction between interim and final rates, and when and on what basis each take effect, in the context of positive tariff approval schemes, as follows:

> Even though Parliament has decided to adopt a positive approval regulatory scheme for the regulation of telephone rates, the added flexibility provided by the power to make interim orders indicates that the [CRTC] is empowered to make orders as of the date at which the initial application was made or as of the date the [CRTC] initiated the proceedings of its own motion. The underlying theory behind the rule that a positive approval scheme only gives jurisdiction to make prospective orders is that the rates are presumed to be just and reasonable until they are modified because they have been approved by the regulatory authority on the basis that they were indeed just and reasonable. However, the power to make interim orders necessarily implies the power to modify in its entirety the rate structure previously established by final order. As a result, it cannot be said that the rate review process begins at the date of the final hearing; instead, the rate review begins when the appellant sets interim rates pending a final decision on the merits.[96]

164. In the result, the Supreme Court had no difficulty in finding that the CRTC, under its then-governing legislation, possessed the necessary authority to issue a remedial one-time credit order, once it was determined that the CRTC could revisit interim rates from the date they were first set. Gonthier J., speaking for the court, made this finding on two different grounds. First, it would serve no purpose if a regulator had the power to revisit interim rates to the date they were first set if there were no corollary power to ensure that they were and remained just and reasonable. Second, Gonthier J. found that the residual powers granted to the CRTC by Section 340(5) of the Railway Act (which was comparable to Section 8(2) of the current *Alberta Utilities Commission Act*) were sufficient for this purpose:

> Once it is decided, as I have, that the [CRTC] does have the power to revisit the period during which interim rates were in force for the purpose of ascertaining whether they were just and reasonable, it would be absurd to hold that it has no power to make a remedial order where, in fact, these rates were not just and reasonable. I also agree with Hugessen J. [dissenting in the Federal Court of Appeal] that s. 340(5) of the *Railway Act* provides a sufficient statutory basis for the power to make remedial orders including an order to give a one-time credit to certain classes of customers.[97]

165. The Supreme Court provided further insight into this finding when it held that:

> [O]ne of the differences between interim and final orders must be that interim decisions may be reviewed and modified in a retrospective manner by a final decision. It is inherent in the nature of interim orders that their effect as well as any discrepancy between the interim order and the final order may be reviewed and remedied by the final order.[98]

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95 *Bell Canada*, pages 1755-1756.
96 *Bell Canada*, page 1761.
97 *Bell Canada*, page 1762.
98 *Bell Canada*, page 1752.

166. The Commission understands this finding to mean that once rates have been declared interim, a regulator is necessarily empowered to not only revisit and, if necessary, revise those rates to ensure that they were and remain just and reasonable prior to setting rates on a final basis, but that the regulator is also empowered to issue remedial orders with retrospective effect. That is, the Supreme Court recognized that there are circumstances where, despite concerns with respect to intergenerational inequity, the statutory obligation to ensure that rates are just and reasonable may justify burdening (or rewarding) current ratepayers with the higher (or lower) rates that should have been borne (or enjoyed) by previous generations of ratepayers.

167. Indeed, the Supreme Court concluded its decision with just such a finding:

> Finally, it is true that the one-time credit ordered by the [CRTC] will not necessarily benefit the customers who were actually billed excessive rates. However, once it is found that the [CRTC] does have the power to make a remedial order, the nature and extent of this order remain within its jurisdiction in the absence of any specific statutory provision on this issue. The [CRTC] admits that the use of a one-time credit is not the perfect way of reimbursing excess revenues. However, in view of the cost and the complexity of finding who actually paid excessive rates, where these persons reside and of quantifying the amount of excessive payments made by each, and having regard to the [CRTC's] broad jurisdiction in weighing the many factors involved in apportioning [Bell Canada's] revenue requirement amongst its several classes of customers to determine just and reasonable rates, the [CRTC's] decision was eminently reasonable and I agree with Hugessen J. that it should not be overturned.[99]

168. The Commission takes from this finding that where a remedial order is otherwise authorized and just, the difficulty of arriving at a solution that meets all practical business, operational and public policy concerns is not a reason in itself for declining to issue such a remedial order.

169. The Commission concludes on the basis of this examination of the common law on interim ratemaking that a regulatory tribunal such as the Commission can set interim rates and that where interim rates are in place, they can be revised with retrospective effect unless there exists express statutory language to the contrary.[100] There is no provision in the Commission's governing legislation and, in particular, in those sections of the 2003 and 2003/07 *Electric Utilities Act* dealing with its ratemaking powers, that expressly prohibit revising interim rates with retroactive or retrospective effect to the date they were approved. In the Commission's view, the Supreme Court's decision in *Bell Canada* supports the proposition that were the Commission to find that a utility's interim rates were unjust and unreasonable, it would possess the necessary authority to issue a remedial order that could include a one-time credit or surcharge to affected ratepayers, notwithstanding its retrospective effect.

4.3.2 Deferral accounts

170. The common law in Canada with respect to a regulatory agency's powers to retroactively revise rates made subject to a deferral account is very similar to the law applicable to an administrative tribunal's authority to retroactively revise rates approved on an interim basis.

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99 *Bell Canada*, pages 1762-1763.

100 In the instant case, the Commission's governing legislation expressly allows it to set interim rates and to make interim orders (Section 124(2) of the *Electric Utilities Act* and Section 8(5)(c) of the *Alberta Utilities Commission Act*, respectively).

171. One of the leading cases in this regard is the decision of the Supreme Court of Canada in *Bell Canada* v. *Bell Aliant Regional Communications*, [2009] 2 SCR 764, 2009 SCC 40 (*Bell Alliant*). The *Bell Alliant* case involved a CRTC order directed at all regulated incumbent local exchange carriers subject to its newly created Price Caps regime to "establish deferral accounts as separate accounting entries in their ledgers to record funds representing the difference between the rates actually charged and those otherwise determined"[101] in the CRTC's price cap formula setting the maximum level of prices that could be charged for certain services. The May 2002 order establishing these deferral accounts made no mention of how the funds in these accounts would eventually be used or disposed of.

172. Following an application by Bell Canada, a subsequent public process was undertaken to determine the disposition of the funds in these accounts. In May 2006, the CRTC ordered that the deferral account funds be used for the expansion of high-speed broadband internet services in rural and remote communities and for improved access to telecommunications services for individuals with disabilities, with any unspent remainder to be distributed to certain existing residential customers by way of a one-time credit or through prospective rate reductions. A unanimous Federal Court of Appeal dismissed all appeals of the CRTC's decision, as did a unanimous nine-member panel of the Supreme Court of Canada.

173. After carefully reviewing the CRTC's rate-setting powers and very broad policy mandate under the *Telecommunications Act*, the Supreme Court noted that deferral accounts are a standard regulatory tool in the ratemaking process, especially where a particular expense or revenue item is difficult to predict because of its inherent volatility.

> No party objected to the CRTC's authority to establish the deferral accounts themselves. These accounts are accepted regulatory tools, available as a part of the Commission's rate-setting powers. As the CRTC has noted, deferral accounts "enabl[e] a regulator to defer consideration of a particular item of expense or revenue that is incapable of being forecast with certainty for the test year". They have traditionally protected against future eventualities, particularly the difference between forecasted and actual costs and revenues, allowing a regulator to shift costs and expenses from one regulatory period to another. While the CRTC's creation and use of the deferral accounts for broadband expansion and consumer credits may have been innovative, it was fully supported by the provisions of the *Telecommunications Act*.[102]

174. The Supreme Court also cited with approval the conclusions of the Federal Court of Appeal in this case. Speaking for a unanimous court, Abella J., held that:

> A deferral account would not serve its purpose if the CRTC did not also have the power to order the disposition of the funds contained in it. In my view, the CRTC had the authority to order the disposition of the accounts in the exercise of its rate-setting power, provided that this exercise was reasonable.
>
> I therefore agree with the following observation by Sharlow J.A.:
>
>> The Price Caps Decision required Bell Canada to credit a portion of its final rates to a deferral account, which the CRTC had clearly indicated would be disposed of

[101] *Bell Alliant*, page 766.
[102] *Bell Alliant*, paragraph 54.

> in due course as the CRTC would direct. There is no dispute that the CRTC is entitled to use the device of a mandatory deferral account to impose a contingent obligation on a telecommunication service provider to make expenditures that the CRTC may direct in the future. It necessarily follows that the CRTC is entitled to make an order crystallizing that obligation and directing a particular expenditure, provided the expenditure can reasonably be justified by one or more of the policy objectives listed in section 7 of the *Telecommunications Act*.[103]
> [Emphasis in original.]

175. In the *Bell Alliant* case, the appellant Bell Canada had argued that the CRTC's order directing one-time credits from the deferral accounts constituted impermissible retrospective ratemaking (within the meaning of that term in the 1989 *Bell Canada* case) as the CRTC had approved its rates on a final, as opposed to interim, basis. This argument was rejected by the court on the following grounds:

> In my view, because this case concerns encumbered revenues in deferral accounts (referred to by Sharlow J.A. as contingent obligations or liabilities), we are not dealing with the variation of final rates. As Sharlow J.A. pointed out, *Bell Canada (1989)* is inapplicable because it was known from the outset in the case before us that Bell Canada would be obliged to use the balance of its deferral account in accordance with the CRTC's subsequent direction (para. 53).[104]

176. Abella J., then added:

> In my view, the credits ordered out of the deferral accounts in the case before us are neither retroactive nor retrospective. They do not vary the original rate as approved, which included the deferral accounts, nor do they seek to remedy a deficiency in the rate order through later measures, since these credits or reductions were contemplated as a possible disposition of the deferral account balances from the beginning. These funds can properly be characterized as encumbered revenues, because the rates *always* remained subject to the deferral accounts mechanism established in the Price Caps Decision. The use of deferral accounts therefore precludes a finding of retroactivity or retrospectivity. Furthermore, using deferral accounts to account for the difference between forecast and actual costs and revenues has traditionally been held not to constitute retroactive rate-setting (*EPCOR Generation Inc. v. Energy and Utilities Board*, 2003 ABCA 374 (CanLII), 346 A.R. 281, at para. 12, and *Reference Re Section 101 of the Public Utilities Act* (1998), 1998 CanLII 18064 (NL CA), 164 Nfld. & P.E.I.R. 60 (Nfld. C.A.), at paras. 97-98 and 175).[105]

177. One further finding of the Supreme Court is instructive. That is:

> The allocation of deferral account funds to consumers was not, strictly speaking, a "rebate" in any event. Instead, as in *Bell Canada (1989)*, these allocations were one-time disbursements or rate reductions the carriers were required to make out of the deferral accounts to their *current* subscribers. The possibility of one-time credits was present from the inception of the rate-setting exercise. From the Price Caps Decision onwards, it was understood that the disposition of the deferral account funds might include an eventual credit to subscribers once the CRTC determined the appropriate allocation. It was precisely

[103] *Bell Alliant*, paragraph 57.
[104] *Bell Alliant*, paragraph 61.
[105] *Bell Alliant*, paragraph 63.

> because the rate-setting mechanism approved by the CRTC included accumulation in and disposition from the deferral accounts pursuant to further CRTC orders, that the rates were and continued to be just and reasonable.[106]
> [Emphasis added]
>
> Therefore, rather than viewing *Bell Canada (1989)* as setting a strict rule that subscriber credits can never be ordered out of revenues derived from final rates, it is important to remember Gonthier J.'s concern that the financial stability of regulated utilities could be undermined if rates were open to indiscriminate variation (p. 1760). Nothing in the Deferral Accounts Decision undermined the financial stability of the affected carriers. The amounts at issue were always treated differently for accounting purposes, and the regulated carriers were aware of the fact that the portion of their revenues going into the deferral accounts remained encumbered.[107]
> [Emphasis added]

178. What this finding (and that excerpted above from the decision of Sharlow J.A. in the Federal Court of Appeal) points to is that knowledge of the parties that rates were subject to change or, equivalently, that a portion of revenues collected under approved rates remained encumbered, is an essential factor explaining why revising interim rates, no less so than rates (or, equivalently, revenues) subject to a deferral account, does not constitute impermissible retroactive or retrospective ratemaking. Where affected parties know, or ought to know,[108] that a regulatory process has been initiated that can affect final rates or revenues, the policy concern with respect to the potential commercial harm attending uncertainty in rates is much diminished. This point will be discussed at greater length in section 4.3.4 below as it constitutes a further judicially recognized exception to the general presumption against retroactivity in ratemaking.

179. Another useful case to consider on the subject of deferral accounts is that of the Alberta Court of Appeal in *Calgary (City)* v. *Alberta (Energy and Utilities Board),* 2010 ABCA 132 (*Calgary*). This decision involved consideration of the use of deferred gas accounts (and their predecessor regulatory instrument -- gas purchase adjustment clauses) in the ratemaking process and is significant both for the very detailed history it provides of how these accounts came into being as well as their inherent strengths and weaknesses in assisting regulatory tribunals in setting just and reasonable rates for consumers of natural gas. The basic concept underlying the introduction of deferred gas accounts into the ratemaking process was to provide a mechanism for reconciling actual to estimated costs of gas arising from the difficulty in forecasting gas costs because of seasonal price volatility. The mechanism ensured that neither consumers nor the gas utility would be prejudiced by unpredictable gas costs.

180. What is most relevant to this proceeding is Hunt J.A.'s majority judgment addressing the question of whether deferred gas accounts are interim or final in nature. On the facts of the *Calgary* case this matter was unclear from the record before the court. However, according to the majority of the court, whether rates (or in this case, gas costs) that were subject to a deferred gas account were interim or final was immaterial to the outcome. What mattered was the knowledge of the parties as to whether rates were ultimately subject to change. According to Hunt J.A.:

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106 *Bell Alliant*, paragraph 65.
107 *Bell Alliant*, paragraph 66.
108 See, for example *Salt Caverns II*, paragraph 61.

> Both *Bell Canada 1989* and *Bell Aliant* (which concerned deferral accounts rather than interim rates) illustrate the same preoccupation: were the affected parties aware that the rates were subject to change? If so, the concerns about predictability and unfairness that underlie the prohibitions against retroactive and retrospective ratemaking become less significant.
>
> Were these parties aware that gas rates were potentially subject to change through the use of the DGA [deferred gas account]? If so, whether the rates are characterized as interim or final, the principles in *Bell Aliant* govern.
>
> The history of DGAs demonstrates that affected parties knew they would be used from time to time to alter gas rates based on later, actual gas costs. Indeed, the Board so found as a fact[.]
>
> Reconciliation of the DGA/GCRR [Gas Cost Recovery Rate] would sometimes benefit consumers and sometimes not. Gas rates sometimes changed because of the lack of predictability (volatility) in gas prices and sometimes from other factors such as measuring errors. Whatever the cause, the objective was to ensure that the consumer paid the actual cost of the gas. This legitimate object was accepted by all parties. It strengthened the utility regulatory system by ensuring that the utility received a fair rate of return on its rate base.
>
> Therefore, whether the rates should be characterized as final or interim, the use of the DGA in this case did not involve prohibited ratemaking.[109]
> [Emphasis added]

4.3.3 Negative disallowance

181. As noted earlier, tariffs can come into effect in one of two ways: pursuant to positive approval schemes or pursuant to negative disallowance schemes. The Supreme Court of Canada, in *Bell Canada* considered the principal differences between these two types of tariff approval mechanisms, and summarized the differences as follows:

> Much was said in argument about the difference between positive approval schemes and negative disallowance schemes with respect to the power to act retrospectively. The first category includes schemes which provide that the administrative agency is the only body having statutory authority to approve or fix tolls payable to utility companies; these schemes generally stipulate that tolls shall be "just and reasonable" and that the administrative agency has the power to review these tolls on a *proprio motu* basis or upon application by an interested party. The second category includes schemes which grant utility companies the right to fix tolls as they wish but also grant users the right to complain before an administrative agency which has the power to vary those tolls if it finds that they are not "just and reasonable". It has generally been found that negative disallowance schemes provide the power to make orders which are retroactive to the date of the application by the ratepayer who claims that the rates are not "just and reasonable". On the other hand, positive approval schemes have been found to be exclusively prospective in nature and not to allow orders applicable to periods prior to the final decision itself.[110]

182. The process followed by the Commission in approving line loss charges in the ISO tariff is, in substance, a negative disallowance scheme, not a positive approval scheme. The case law on negative disallowance schemes therefore governs whether a remedy exists for parties that

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[109] *Calgary*, paragraphs 57-61.
[110] *Bell Canada,* page 1758-1759.

have been harmed by rates found to have been unlawful after having come into effect pursuant to a negative disallowance scheme.

183. One of the leading Canadian cases on the ratemaking powers of a regulatory agency under a negative disallowance tariff scheme is *Nova*. Among the issues before the Supreme Court in that decision was whether a predecessor of the Commission, the Public Utilities Board of Alberta, was statutorily empowered to retroactively or retrospectively alter rates for the transportation of natural gas in Alberta upon receiving a complaint in writing from an interested party against the rates set at first instance by *Nova* pursuant to the negative disallowance scheme established by the governing legislation.

184. The court began its decision with a thorough review of the scheme and history of the operative provisions of the governing legislation. It also looked at similar legislation in other jurisdictions for additional guidance on how to interpret the applicable statute. Section 30 of the *Alberta Gas Trunk Line Company Act* provided as follows:

> **30.** (1) The company shall from time to time fix and may from time to time vary the rates, tolls and other charges, including the rates and methods of depreciation and amortization, determination of rate base and rate of return thereon, for the gathering, treating, transporting, storing, distributing, commingling, exchanging, handling and delivery of gas carried by its pipe lines and other facilities or any part or parts thereof or for any service performed by the company in relation to the gathering, treating, transporting, storing, distributing, commingling, exchanging, handling or delivery of any gas.
>
> (2) Upon complaint in writing of an interested party, the Public Utilities Board may, or upon the direction of the Lieutenant Governor in Council shall, after notice to and hearing of the parties interested, determine the justness and reasonableness of the rates, tolls or other charges fixed or varied by the company and by order in writing may vary or confirm the rates, tolls or other charges.
>
> (3) Where the Public Utilities Board varies a rate, toll or other charge fixed or varied by the company, its order shall specify that the variation shall remain in full force and effect until a specified date or until the date of the happening of a specified event but in no case shall the period involved exceed 12 months.[111]

185. Estey J. speaking for the court, found as follows:

> In construing the first three subsections of s.30 it is imperative to bear in mind that the scheme of the Act contemplates the transportation company, Nova, to be the moving party. Nova has the right to take the initiative to place in effect the rates, tolls and other charges which it wishes to recover from the users of its facilities. It is the plan of the *AGTL Act, supra,* that the user of these facilities, if it finds the rates imposed by the company to be excessive, may institute a complaint in writing to the Board. The statute then requires the Board to determine the justness and reasonableness of the rates and to either vary or confirm those rates according to its findings. Viewed in the light of this statutory pattern the terminology employed by the Legislature in my view lends itself readily to the construction authorizing the Board to vary the rates proposed by the company, at least retroactively to the point where the complaint was filed by a user of the company's facilities.[112]

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[111] *Nova*, page 440.
[112] *Nova*, page 450.

186. In reaching this conclusion, Estey J. carefully considered the meaning of the terms "vary" and "varies" in Sections 30(2) and 30(3) of the *Alberta Gas Truck Line Company Act* cited above. According to Estey J.:

> The appellant chooses to approach the problem of retroactivity by commencing at s. 30(3). That subsection expressly provides that the Board's "variation shall remain in full force and effect until a specified date…" In the view of the appellant "the entire thrust of the section is prospective…" and "can only be read as meaning that any variation shall take effect at the date of the order and continue in effect into the future". A different hue is placed upon the subsection if the interpretation commences at the beginning of the subsection with the verb "varies". In the context of the sentence that verb has neither retroactive nor prospective application of necessity. Similarly subs. (2) is capable of bearing the sense of retroactivity in any order which "may vary or confirm the rates or tolls or other charges". Clearly those rates and tolls, by the pattern adopted by the legislation, must be those established by Nova prior to the initiating complaint. It follows logically that the Board's requested review should commence at least at the date of the complaint about those company-established rates. The words of subs. (2) are capable of supporting the conclusion that the legislative intent was to enable the Board to make a variation to those company-imposed rates and tolls, where the Board has found them to be "unjust and unreasonable", with retroactive effect at least the date of the complaint."[113]

187. The Supreme Court then took note of the fact that the operative provisions of the *Alberta Gas Trunk Line Company Act* nowhere obliged *Nova*, in setting rates, to ensure that they were just and reasonable. This notwithstanding, the court still found that the statutory scheme of the Act entailed a presumption that rates were just and reasonable from the outset. This presumption, however, could be rebutted upon the rates being successfully challenged pursuant to a written complaint and a subsequent Board determination that they were unlawful. The court also found that where there are many elements to a rate that is subject to a negative disallowance scheme, a complaint with respect to only some of those elements does not compel the regulator to investigate whether all of the elements are just and reasonable. According to Estey J.:

> Quite apart from the factual background, it follows inexorably that if Nova has, pursuant to the statutory directives of the Act, established rates which have been paid up until the complaint at least by the producers, then the rates of the company so in place are taken to be just and reasonable. By their complaints the producers have placed in issue only the question of depreciation and income taxes, and otherwise, by their silence, have accepted the balance of the components in Nova's rates as being just and reasonable. The Board, in not responding to these complaints other than to deal with and dispose of the two items so advanced, must be taken to have assumed that nothing passing before the Board in these hearings has occasioned it to find any element of unjustness or unreasonableness in Nova's rates apart from the two items complained of. Unless the statute, by very precise and specific language, were to impose upon the regulatory authority the burden, on the hearing of every complaint, of investigating the basic and complete justness and reasonableness of rates established by the deliverer of the services in question, a court should be loathe to read such an unusual meaning into the words employed by the Legislature. I decline to do so on the basis of the terminology of the Act here before us.[114]

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113 *Nova*, page 448.
114 *Nova*, page 454.

188. The court also observed that Section 30(3) of the governing legislation limited to 12 months the duration of any variance in rates that might be ordered by the Public Utilities Board should it find that the rates imposed by *Nova* were not just and reasonable. This meant that if the regulatory process of investigating a complaint before upholding it on the merits took more than 12 months, further hardship would befall ratepayers. Under these circumstances, the Supreme Court concluded that the enabling legislation should be interpreted as authorizing the Public Utilities Board to retroactively revise rates found upon complaint to be unjust and unreasonable up to the maximum allowed period of 12 months or the time that had passed since the complaints were made, whichever was shorter. The court then made a very important observation. It stated that if the negative disallowance scheme were interpreted as permitting *only* prospective relief, the same mischief could simply repeat itself.

> The second result is that Nova is free upon the expiry of the order at the end of 1978 to establish, once again, whatever rates it may wish to recover from its customers; subject of course to the right in an interested party to file a complaint, as indeed was done here by the producers. If the Board is confined by the wording of s. 30 to prospective orders, considerable hardship will fall upon the recipients of Nova's services in that the charges therefor would be recoverable throughout the period during which the Board must devote its processes to a determination as to whether those rates imposed by Nova are in fact just and reasonable. If the Board, after this prolonged and complex process, determines that the rates placed in effect by Nova are indeed unjust and unreasonable, then the gas producers will necessarily have paid during the protracted period after their complaint, unjust and unreasonable charges for Nova's services. I do not read the provisions in s. 30(2) and (3) as requiring such a result and I respectfully find myself in agreement with the majority of the Court of Appeal in finding that the Board orders, made effective January 1, 1978, are within the authorization of the *AGTL Act, supra.*[115]

189. In other words, it was the conclusion of the court that where rates are set at first instance pursuant to a negative disallowance scheme, the regulatory agency must be taken to have the authority to revise rates with retroactive effect, at least to the date the complaint was made (subject to any other statutory restrictions that might limit the extent of retroactivity, as was the case in *Nova*) in order to minimize the injustice to parties harmed by the imposition of rates subsequently found to be unjust and unreasonable. In the Commission's view, these considerations apply equally here given the Commission's finding that the tariff approval process for line loss charges incorporated into the ISO tariff constitutes a negative disallowance scheme under both the 2003 and 2003/07 *Electric Utilities Acts*.

190. The Commission also relies on an additional observation made by the court in *Nova.* Referring to the concurring (yet, on several points, dissenting) opinion of Pratte J.A. in the court below, Estey J. noted the latter's concern that "the appellant was attempting to retain the benefits of the "rate of return" decision reached in the parallel proceedings, while attacking the order presently in issue. The two, he held, together fixed the company's rates for 1978. It was not open to the appellant, he said, to approve and reject those rates at the same time by appealing one decision while seeking to retain the benefit of the other."[116] The Commission understands this to mean that the Supreme Court was conscious of the increased potential for strategic or opportunistic behaviour by parties seeking to retain the benefit of unlawful rates if negative disallowance schemes are interpreted as permitting only prospective relief upon a complaint

[115] *Nova*, page 451.
[116] *Nova*, page 444.

being upheld. A similar point was made in *Coseka*, which dealt with whether interim rates could be revised retroactively upon being found to be unjust and unreasonable. The Supreme Court observed that if interim orders cannot be changed as of the date they first took effect, parties would have an incentive to delay proceedings in order to obtain the benefit of unjust and unreasonable rates for as long as possible.[117]

191. The Commission, in making these observations, seeks only to underline that courts have long been aware of the potential incentives for regulatory delay if interim rates cannot be revised with retrospective effect or if all but prospective relief (upon successful complaint) is denied under a negative disallowance scheme.

4.3.4 Knowledge that rates might change

192. The Alberta Court of Appeal has recently considered the relationship between permissible retroactivity in ratemaking and knowledge of affected parties that rates are subject to change, whether such knowledge comes from the words or actions of the regulator or from the very nature of the legal or regulatory proceedings in which rates have been called into question.

193. In *Salt Caverns II*, one of the issues was whether the Commission had breached the rule against impermissible retroactive ratemaking when it backdated the effective date of the removal of certain assets from the regulated rate base of ATCO Gas and Pipelines Ltd. The assets in question were no longer required for utility purposes. The court described the considerations it would take into account in determining this issue as follows:

> Whether a decision is impermissible retroactive ratemaking is an issue of fact. (See *Atco Gas, Re*, 2010 ABCA 132 (CanLII), 477 AR 1, discussed below.) There are two fundamental policy concerns behind retroactive ratemaking. With regard to the utility, retroactive ratemaking is unfair because a utility relies on certain rates to make business decisions. To change them after the fact could cause unexpected results for the utility: Yvonne Penning, “Can Economic Policy and Legal Formalism Be Reconciled: The 1986 Bell Rate Case” (1989) 47 *U Toronto Fac L Rev* 607 at 610. With regard to consumers, retroactive ratemaking redistributes the cost of utility service by asking today’s customers to pay for expenses incurred by yesterday’s customers: “Can Economic Policy and Legal Formalism Be Reconciled” at 610. Clearly, that should be avoided.[118]

194. The Court of Appeal then enunciated a general test for when retroactive rate changes are permissible that is independent of the specific label or description of the type of proceeding in which they are made:

> Once there is knowledge [that rates might change], the harm of retroactive ratemaking from the utility’s perspective vanishes.[119]

195. The Court of Appeal went on to state as follows:

> Simply because a ratemaking decision has an impact on a past rate does not mean it is an impermissible retroactive decision. The critical factor for determining whether the regulator

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117 *Coseka*, paragraph 37.
118 *Salt Caverns II*, paragraph 51.
119 *Salt Caverns II*, paragraph 53.

is engaging in retroactive ratemaking is the parties' knowledge. Hunt JA in *Calgary (City) v Alberta (Energy and Utilities Board)*, 2010 ABCA 132 (CanLII), 477 AR stated at para 57:

> Both *Bell Canada 1989* [*Bell Canada v Canada (Canadian Radio-Television and Telecommunications Commission)*, 1989 CanLII 67 (SCC), [1989] 1 SCR 1722] and *Bell Aliant* [*Bell Canada v Bell Aliant Regional Communications*, 2009 SCC 40 (CanLII), [2009] 2 SCR 764] (which concerned deferral accounts rather than interim rates) illustrate the same preoccupation: **were the affected parties aware that the rates were subject to change?** If so, the concerns about predictability and unfairness that underlie the prohibitions against retroactive and retrospective ratemaking become less significant. [Emphasis in original.]

If a utility is aware that a rate is interim and subject to change, then a regulator's revision of the rate will not be disallowed for impermissible retroactive ratemaking. This was the conclusion reached by the Supreme Court of Canada in *Bell Canada v Canada (Canadian Radio-Television and Telecommunications Commission)*, 1989 CanLII 67 (SCC), [1989] 1 SCR 1722, 60 DLR (4th) 682 [*Bell Canada 1989*].

According to the Supreme Court of Canada in *Bell Canada 1989* at 1756, alteration of an interim rate by a regulator is simply a function of regulators who have the mandate to ensure rates and tariffs are, at all times, just and reasonable.

In this appeal, the Commission expressly reserved the issue of the salt cavern assets, among others, from the revenue requirement determination: Commission's Decisions 2009-033 and 2010-228. Atco says the use of a placeholder (reserving the issue of the salt cavern assets for future determination) was not enough to enable the Commission to revisit the matter in subsequent years. Atco submits that the terms "interim rate order" and "deferral account" are well understood by all parties and that the use of the word "placeholder", without more, is not enough to achieve the same purpose as interim rates and deferral accounts. I do not agree. Atco had all the information it required by June 2009 to know that it was not entitled to revenue from inclusion of those assets in the rate base.[120]

…

Not only did Atco agree to deal with the salt cavern assets in a separate proceeding, it was aware that the revenue requirement would change as a result of removal of the assets. Although there was no discussion about interim rates or deferral accounts, Atco had knowledge that the impact of the subsequent proceeding could result in a different revenue requirement. It not only can be taken to have known that it could remove the assets from the rate base, but the reservation of the issue of the salt cavern assets for a future proceeding certainly supports the Commission's finding here.

<u>Slavish adherence to the use of interim rates and deferral accounts should not prohibit adjustments in a case such as this. Regulators have a broad, discretionary authority when ratemaking. The relevant question here is whether the utility knew from the actions or words of the regulator that the rates were subject to change.</u> Atco clearly knew since 2007 that the identified salt cavern assets were not being used or required for operations of the utility. Atco's submission that a commission can only change rates if it used an interim rate or deferral account misapprehends the reason why deferral accounts and interim rates can be retrospectively altered by a regulator. <u>The question here is not whether the regulator used the</u>

[120] *Salt Caverns II*, paragraphs 56-59.

> name "deferral accounts" or "interim rates" but whether Atco was aware that the rate could be altered retroactively.[121]
> [Emphasis added][122]

196. In the Commission's view, the above-excerpted passages from the Alberta Court of Appeal's decision in *Salt Caverns II* stand for the following four propositions. First, as a general rule, it is the knowledge of affected parties that rates may change which renders permissible what would otherwise be impermissible retroactive ratemaking. Second, knowledge that rates may be subject to change can be acquired in more than one way. Third, in some cases, it will be obvious from the very nature (if not nomenclature) of the regulatory proceeding in which rates are being examined, that the outcome of the proceeding may involve retroactive or retrospective changes to past rates.[123] As the court itself noted, regulatory proceedings in which no question of impermissible retroactive ratemaking arises include those expressly dealing with interim rates. ATCO Gas and Pipelines Ltd., which was the appellant in *Salt Caverns II*, argued that deferral account proceedings equally raise no question of impermissible retroactive ratemaking, and the court did not disagree. Instead, it explained that the *reason* such proceedings do not involve impermissible ratemaking is not (necessarily) because of the label attached to them or the subject matter they deal with (although in certain cases that may suffice) but, rather, because all parties know (or "can be taken to have known") from the outset of such proceedings that rates may change. And fourth, in other situations, it may be less obvious from the name or general nature of the proceeding that rates may change with retroactive or retrospective effect. In those situations, it will be necessary for the regulator to place parties on notice, by its words or actions, that rates may be subject to change. The Commission concludes from this that in situations where the very nature (and, indeed, ultimate purpose) of the proceeding is to determine whether past rates should be revised with retroactive effect if they are found not to have been just and reasonable, no additional notice of such possible outcome is required from the regulator for affected parties to possess the required knowledge that rates may change.

197. In view of this jurisprudence (and the Commission's understanding of it), the Commission must next consider the following question. Did those market participants who were subject to the ISO's Line Loss Rule know that line loss charges in the ISO tariff may be subject to change once (1) Milner filed its 2005 complaint against the ISO's Line Loss Rule and at the same time filed its objection to the rates that would be included in the ISO tariff or, (2) Milner filed for leave to appeal EUB Decision 2005-150 after its complaint had been dismissed by the Board in that decision? The Commission notes here that when the words "subject to change" are used in reference to (1) line loss factors produced by the ISO's Line Loss Rule or (2) the line loss charges in the ISO tariff that derive from those line loss factors, it does not understand these words to mean that the tariff rates in question "must" or "will" change. Rather, these words mean

[121] *Salt Caverns II*, paragraphs 61-62.

[122] The Commission notes here that this expression of the law is consistent with the passage from *Sullivan on the Construction of Statutes* quoted earlier and relied upon by the respondents in the instant proceeding to oppose any possibility of retroactive ratemaking, viz., "…the fundamental principle on which rule of law is built is advance knowledge of the law." Once there is "advance knowledge of the law", however, the jurisprudence holds that the presumption against retroactivity is much diminished, if not altogether eliminated.

[123] The fact that the requisite knowledge that rates may change can come from the very nature of a regulatory order was expressly made by AltaGas in its written reply argument. According to AltaGas, "It is not disputed that this knowledge can arise from an interim rate approval or the establishment of a deferral account, which guarantee that a rate can be revisited in future." Exhibit 556.02, AltaGas Reply Argument, October 22, 2014, page 7, paragraph 17.

only that rates "could" change following a final determination with respect to Milner's complaint against the ISO's Line Loss Rule.

198. Milner, ATCO Power and Powerex have argued in this proceeding that all affected parties either knew or ought to have known that line loss charges and credits in the ISO tariff were subject to change from the time Milner filed its original complaint (and simultaneously attempted to intervene in the AESO's 2005/2006 GTA based on its concerns with respect to the ISO Line Loss Rule that was set to come into effect on January 1, 2006).[124]

199. ATCO Power, for example, made the following submissions in its written argument with respect to the knowledge exception to the rule against retroactive ratemaking:

> In the context of the Board's consideration of the AESO 2005/2006 General Tariff Application ("GTA")(Decision 2005-096), the Board directed that complaints respecting loss factors be addressed outside the GTA process, stating (page13) that parties with a complaint regarding loss factors "are free to file a complaint with the Board if they are not satisfied with the AESO's proposal for the setting of loss factors". This is indeed what Milner did in the context of the Line Loss Rule proposed by the AESO to establish those loss factors. Further, the AESO's submissions in the GTA proceeding confirmed that "as transmission loss factors are to be established through the AESO rules, it is expected that the EUB would review the adjustments on a complaint basis only."(page 13)
>
> ATCO Power submits that this direction from the Board and the confirmation of the AESO respecting the process for adjustments related to loss factors, together with the actual filing of a complaint in accordance with the Board's direction, the issuance of Board and Commission notices, and numerous related processes before the Board, the Commission and the Courts, should be considered to have provided sufficient knowledge on the part of the Board, the Commission, the AESO and market participants regarding the potential for rates to change.[125]

200. Powerex has similarly argued that:

> Clearly, most of those adversely affected by the change requested by Milner have been very active participants throughout the complaint process since 2005. Under the principles established in *ATCO,* none of those parties can be heard to complain that they are taken by surprise by the fact that the Loss Factor and the Line Loss Rule have been adjusted by the Commission. Milner has been pushing for just that remedy ever since it filed its Complaint and they have been resisting it. All relevant parties have known throughout that an adjustment may be coming.[126]

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124 Exhibit 549.01, Milner Argument, September 24, 2014, page 2, paragraph 10; exhibit 548.01 ATCO Power Argument, September 24, 2014, page 25, paragraph 91; and exhibit 541.01, Powerex Argument, September 24, 2014, page 8, paragraph 27.

125 Exhibit 548.01, ATCO Power Argument, September 24, 2014, pages 24-25, paragraphs 90-91.

126 The Commission notes here that, contrary to Powerex's assertion, it has not actually adjusted the Line Loss Rule, any line loss factors produced by the rule or any line loss charges in the ISO tariff that are derived from the line loss factors produced by the rule. Rather, to date, all the Commission has found is that the Line Loss Rule and the associated MLF/2 methodology used to calculate line loss factors are contrary to the governing legislation and regulations and, thus, are unlawful and have been unlawful since the rule was first introduced on January 1, 2006. The Commission has further found in Module A of this proceeding, however, that once a Line Loss Rule has be found to be unlawful, the line loss charge components in the ISO tariff that are determined by the rule are likewise unlawful.

> Powerex goes further and submits, with respect, that if ever there was a notorious complaint with respect to the AESO's rates, this case is it. The present proceeding does not deal with the rates of residential customers who may have little or no awareness of the issues before the Commission. To the contrary, this proceeding relates to a limited class of generators and importers/exporters in Alberta. To the extent that the members of the relevant class were not participating in the proceeding, there can be no doubt that they, like Powerex, were watching for its result. They must be taken to have known that the charges and credits for losses associated with their activities were subject to change.[127]

201. The Commission notes in this regard that a number of the participants in this proceeding also participated in the AESO’s 2005/2006 GTA proceeding. As Powerex also correctly observes, and no other parties dispute, several of the participants in this proceeding have also been active participants at every stage of the Milner complaint process, whether before the EUB, the Court of Appeal or this Commission.[128]

202. The respondents, for their part, deny that that they knew or could have known that Milner’s 2005 complaint might in any way affect line loss charges in the ISO tariff, at least until those charges were made interim in Decision 2014-242.[129]

203. TransAlta, for example, made the following submissions on the inapplicability of the knowledge exception based on its interpretation of *Salt Caverns II* and the factual circumstances of this proceeding:

> In summary, this is not a case where parties have “knowledge” regarding the potential retroactive application of an easy-to-understand rate or tariff, or a straight-forward complaint that proceeds expeditiously with a clearly-limited time frame for compensation. What we have in this case is an extraordinarily complex Line Loss Rule which has been the source of a battle between Ph.D. economists and electrical engineers for close to a decade; where the amount of compensation is entirely uncertain; where it is not yet clear how (or indeed if) such compensation can be determined; where the number of parties who are entitled to such compensation is also entirely uncertain; and where the time frame for compensation could be anything from zero to nine years (and counting).[130]

204. AltaGas likewise argued that the knowledge exception does not apply in the circumstances of the present proceeding:

> [T]he instant proceedings have not yet progressed to the point where it can be said that any party has attained any degree of knowledge, or even constructive knowledge, of the rate consequences of the Complaint.[131]
>
> …

127 Exhibit 541.01, Powerex Argument, September 24, 2014, page 8, paragraph 27.

128 The following parties filed submissions with the EUB in 2005 with respect to the Milner complaint: AltaGas, ENMAX, TransAlta, the Industrial Power Consumers Association of Alberta (IPCAA), ATCO Power, Powerex, Calpine Canada, EPCOR Utilities Inc., the Utilities Consumer Advocate and Luscar Ltd.

129 Exhibit 554.01, TCE Reply Argument, October 22, 2014, page 10, paragraph 37.

130 Exhibit 545.01, TransAlta Argument, September 24, 2014, page 19, paragraph 77.

131 Exhibit 556.02, AltaGas Reply Argument, October 22, 2014, page 7, paragraph 16.

> To paraphrase the Court of Appeal…the relevant question is "whether the [market participants] knew from the actions or words of the regulator that the rates were subject to change." It is not disputed that this knowledge can arise from an interim rate approval or the establishment of a deferral account, which guarantee that a rate can be revisited in future. In the context of the *ATCO Gas & Pipelines* decision, the level of knowledge is likewise a certainty: assets admittedly not used or useful must be removed from rate base, with rate implications assumed to be understood as of the date knowledge was acquired. This level of "knowledge" is clearly not present in the instant situation. As TransAlta has pointed out in detail, the history of the Complaint has been discontinuous at best. The "actions or words of the regulator" have been even more inconsistent. The Complaint was dismissed before the first tariff referencing the Rule came into effect. Next followed a number of review applications, judicial reviews and appeals on procedural matters. At many points in its existence, the Complaint languished on a docket, unsure that it would ever be heard: not until 2010 was it even certain that the substance of the Complaint would ever be addressed. Even then a hearing and a review application were necessary before there was any degree of certainty to the substantive result of the Complaint.
>
> Furthermore, the only "knowledge" gained from Decision 2014-110 is the knowledge that the Rule is non-compliant. The Commission has said nothing about rates – indeed, the entire purpose of this Module is to permit the Commission to determine whether a change to the Rule necessitates changes to the related rates. No market participant, let alone all of them, can possibly "kn[o]w from the actions or words of the regulator that the *rates* were subject to change". The argument that market participants had knowledge since the Complaint was brought that all intervening *rates* were subject to change presupposes the very conclusion it seeks to support. It is logically self-contradictory and must be wrong.
>
> Third, no party has referred to any evidence that could possibly establish that any market participant, let alone all of them, had knowledge that past rates were subject to change.[132]

205. Other arguments made by the respondents in this proceeding can also be understood as having a bearing on the knowledge issue. For example, the respondents have variously (and not always consistently) argued that (1) the 2005 Line Loss Rule complained of by Milner was replaced by the 2009 Line Loss Rule and, hence, the original 2005 complaint came to an end on December 31, 2008;[133] (2) the first complaint against the 2009 Line Loss Rule was not made until June 11, 2012; (3) the 2007 amendments to the 2003 *Electric Utilities Act* included Section 25(9)

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132 Exhibit 556.02, AltaGas Reply Argument, October 22, 2014, pages 7-8, paragraphs 17-19. The Commission disagrees with AltaGas' suggestion that it is (or was) incumbent upon the claimants to provide evidence of what market participants knew (or did not know) in relation to the possibility that rates might change as a result of Milner's complaint. As Côté J.A. observed in his concurring judgment in *ATCO Gas and Pipelines Ltd* v *Alberta (Utilities Commission),* 2014 ABCA 397 at paragraph 149, "it is usually almost impossible to prove a negative." In the Commission's view, to do what AltaGas has suggested the claimants should have done would amount to essentially the same task, that is, provide evidence to disprove the claim made by respondents that they did not know that rates may change as a result of a complaint having been made against the Line Loss Rule.

133 Thus, Capital Power Corp. states that, "Milner Power has argued that it intended throughout that the Milner Power Complaint apply to the Current Rule. With respect, whatever may have been Milner Power's intention, it did not disclose it in any effective way and the Milner Power Complaint cannot be said to have "continued" in the sense of having any legal or practical effect as concerns anything other than the 2005 Rule. Neither the AUC nor any interested person should be left to guess at whether an ISO Rule is the subject of an objection or complaint. The very fact that the question continues to be debated more than four years after this Proceeding was commenced proves this point. (See exhibit 543.01, Capital Power Argument, September 24, 2014, page 3, paragraph 15.)

which precludes retroactive changes to ISO rules, including the Line Loss Rule; (4) complaints made under Section 25 of either the 2003 *Electric Utilities Act* or the 2003/2007 Act have no bearing whatsoever on the ISO tariff, including the line loss charges in the ISO tariff; (5) if Milner were seeking financial compensation then it should have applied to the Commission for an order making interim the line loss charges in the ISO tariff; and (6) it makes no difference whether the line loss charges in the ISO tariff are, or at any point were, made interim since no changes to the Line Loss Rule (and the line loss charges that flow from the rule to the ISO tariff) can be made retroactively.

206. After considering all of the arguments made by all of the parties to this proceeding with respect to the knowledge exception, bearing in mind that the Commission has already found the Milner complaint to be a continuing complaint and the Line Loss Rule to have continued materially unchanged since it first came into effect in 2006, the Commission further finds as follows. First, the very nature of a negative disallowance scheme is such that once a complaint is made pursuant to that scheme, all affected parties must be taken to know two things: (1) that the object of the complaint (be it a tariff, a rule, or any part thereof) may change, and (2) if the complaint is upheld, not only may the object of the complaint change, it may change with retrospective effect to the date the complaint was first made. Indeed, the Commission understands this to be the import of the argument made by AltaGas when it conceded that, “It is not disputed that this knowledge [i.e., knowledge that rates might change] can arise from an interim rate approval or the establishment of a deferral account, which guarantee that a rate can be revisited in future.” In other words, if the very fact that rates have been made interim or that costs or revenues have been made subject to a deferral account is sufficient to place parties on notice that rates might change retroactively to the date the relevant order was made, then the same reasoning must apply to a complaint made under a negative disallowance scheme. That is, under Canadian common law, two of the distinguishing attributes of a negative disallowance scheme are that once a complaint is made, the impugned rate may be subject to change and, if the complaint is upheld, the impugned rate may change effective the date the complaint was first made (unless the governing statute expressly provides otherwise). If this were not the case, the statutory design of, and legislative intention underlying such approval schemes would be frustrated, if not wholly undermined.

207. Second, in the Commission’s view, once affected parties become aware that rates (or rules) may change (by virtue of a complaint having been made pursuant to a negative disallowance scheme), such knowledge cannot be disavowed by virtue of (1) the complexity of the issues raised by the complaint; (2) uncertainty as to whether relief is available with retrospective effect, or only prospectively; (3) uncertainty as to the actual date upon which relief or compensation may be available; (4) uncertainty as to how compensation (if available) may be calculated; (5) uncertainty as to the magnitude of compensation, if available; (6) uncertainty as to which parties may receive and which parties may be required to pay compensation, if available; (7) the number of judicial and/or regulatory proceedings required to arrive at a final determination on the complaint; or (8) the total length of time it takes to reach a final determination on the complaint. Indeed, the Commission is of the view that much of the opposition to Milner’s complaint since it was first filed has reflected a concern as to the possibility that tariff-based relief may be granted retroactively or retrospectively should Milner’s complaint be made out.

208. Third, the Commission does not understand the Alberta Court of Appeal in *Salt Caverns II* to have limited its findings on the knowledge exception to proceedings involving but a single

market participant. Multiple parties can possess knowledge of the same matter without limitation or diminution.

4.3.5 Nullities

209. A fifth judicially recognized exception to the general principle against retroactive ratemaking and, more generally, retroactive decision-making by administrative tribunals, relates to any final (as opposed to interim) decision or order made by an administrative tribunal that is subsequently determined to be a nullity. In the past, courts have found administrative decisions to be nullities if they were *ultra vires*, that is, made in excess of jurisdiction.

210. The complainants in this proceeding rely on the Federal Court of Appeal's decision in *Telus* as authority for the proposition that an administrative tribunal decision found to be a nullity is of no force or effect (i.e., amounts to "no disposition at all in law"). Thus, replacing it with a decision that complies with applicable legislation does not constitute retroactive ratemaking. The complainants argue that because the Commission has found the Line Loss Rule to be unlawful from the very outset, it must be held to be a nullity and a new Line Loss Rule that does comply with the governing legislation and regulations should be substituted it its place.

211. The Commission, in reviewing relevant judicial authorities, finds that a significant reconsideration (and narrowing) of Canadian law on the issue of what constitutes jurisdictional error began with the decision of the Supreme Court of Canada in *Dunsmuir* v. *New Brunswick,* 2008 SCC 9. That decision was issued subsequent to the Federal Court of Appeal's decision in *Telus* and was followed by several more decisions of the Supreme Court in which it was held that true instances of jurisdictional error are rare. For example, Rothstein J., speaking for a majority of the Supreme Court in *Alberta (Information and Privacy Commissioner)* v. *Alberta Teachers' Association,* 2011 SCC 61 (at paragraph. 33), held that:

> As this Court explained in *Canada (Canadian Human Rights Commission)*, "*Dunsmuir* expressly distanced itself from the extended definition of jurisdiction" (para. 18, citing *Dunsmuir*, at para. 59). Experience has shown that the category of true questions of jurisdiction is narrow indeed. Since *Dunsmuir*, this Court has not identified a single true question of jurisdiction (see *Celgene Corp. v. Canada (Attorney General)*, 2011 SCC 1, [2011] 1 S.C.R. 3, at paras 33-34; *Smith v. Alliance Pipeline Ltd.*, at paras. 27-32; *Nolan v. Kerry (Canada) Inc.*, 2009 SCC 39, [2009] 2 S.C.R. 678, at paras. 31-36).[134]

212. Commission does not consider the nullity exception to be of assistance to its deliberations in this proceeding and relies on other grounds in finding that it possesses sufficient authority under the ratemaking provisions of its governing legislation to order a tariff-based remedy in this proceeding.

4.3.6 Summary of jurisprudence on retroactive and retrospective ratemaking

213. The Commission summarizes as follows its key findings with respect to the common law on retroactive and retrospective ratemaking (in so far as is relevant to this proceeding):

1. Absent express statutory language to the contrary, the general rule against retroactive or retrospective ratemaking does not apply to situations in which

[134] See also, *Canadian National Railway Co.* v. Canada (Attorney General), 2014 SCC 40.

affected parties knew or ought to have known that rates may be subject to change from the date they first came into effect.

2. In some cases, this knowledge necessarily follows from the very nature of the regulatory proceeding in which the justness and reasonableness of rates is being considered. Three examples of regulatory proceedings in which retroactive ratemaking is permissible because affected parties are presumed to have known from the outset that rates may change are proceedings initiated to consider interim rates, deferral accounts or complaints against rates (or rules) subject to negative disallowance schemes.

3. In general, all negative disallowance schemes share the following attributes: (1) rates (or rules) come into effect without prior regulatory review, oversight or approval; (2) rates (or rules) once in effect are presumed to be just and reasonable unless or until challenged by way of written complaint filed by an affected party; (3) once a complaint has been filed, the justness and reasonableness (or, more generally, lawfulness) of the impugned rate (or rule) remains in question until a final determination is made by the regulator either upholding or dismissing the complaint; (4) pending a final regulatory determination of the justness and reasonableness of the impugned rate (or rule), parties remain on notice that the rate (or rule) remains subject to change; and (5) if an impugned rate (or rule) is determined to be unlawful, it may be changed with retroactive or retrospective effect to the date the complaint was first filed (subject to express statutory language to the contrary).

4. The policy concerns that underlay the general rule against retroactive or retrospective ratemaking are much diminished whenever affected parties know that rates may change. Such knowledge also eliminates incentives for parties that have benefited from unjust and unreasonable rates to act opportunistically to the detriment of parties that would otherwise be unjustly harmed by rigid adherence to this general rule.

4.4 Which statute governs available remedies?

214. The Commission has had regard to the following factors in assessing which of the 2003 and 2003/07 *Electric Utilities Act* should govern its findings with respect to potential remedies that might be available to correct for the payment or receipt of unlawful line loss charges and credits included in the ISO tariff: (1) the chronology of events in this proceeding from the time Milner first filed its complaint against the Line Loss Rule; (2) the express terms of the 2003 and 2003/07 *Electric Utilities Act*; (3) sections 36(1)(b) and 35(1)(c) of the *Interpretation Act*, in view of the statutory scheme of the 2003 and 2003/07 *Electric Utilities Act*; and (4) the arguments filed by the parties to this proceeding with respect to all of the above.

4.4.1 Key proceedings under the 2003 *Electric Utilities Act*

215. Section 2 above sets out a chronology of the events leading up to this decision. In reviewing these events, the Commission notes that notwithstanding the amendments to the 2003 *Electric Utilities Act* which came into force on January 1, 2008, the provisions of the 2003 *Electric Utilities Act* have governed the regulatory and judicial proceedings and findings made

therein, almost without exception, since Milner first filed its complaint on August 17, 2005. Of particular note, are the following three proceedings:

- The Alberta Court of Appeal issued its decision in *Milner* on July 29, 2010. In that decision, the court vacated EUB Decision 2005-150 and remitted the matter to the Board (which the court recognized had since become the Commission) "to continue to further investigate or hold a hearing to determine whether there was a contravention of Section 19 [of the 2004 Transmission Regulation] as alleged." To the extent that the Court of Appeal was aware that both the *Electric Utilities Act* and *Transmission Regulation* had been amended by the time it heard Milner's appeal, if not by the time it allowed Milner's appeal, it would appear that the Court was of the view that the matter should continue to be determined under the former provisions of the *Transmission Regulation* and, by implication, the provisions of the 2003 *Electric Utilities Act*, rather than pursuant to the new regulation and amended legislation.

- In Decision 2012-104, a majority panel of the Commission found, among other things, that the Line Loss Rule was contrary to the express provisions of the 2003 *Electric Utilities Act* and the 2004 *Transmission Regulation* for the period up to January 1, 2009. Although the 2004 *Transmission Regulation* remained in force until December 31, 2008 and the Line Loss Rule continued, the amendments to the 2003 *Electric Utilities Act* (including the new test to sustain a complaint) came into force a year earlier on January 1, 2008.

- In Decision 2014-110, the Commission upheld many of the principal findings made by the hearing panel in Decision 2012-104, including that the Line Loss Rule contravened both the 2003 *Electric Utilities Act* and the 2004 *Transmission Regulation* between January 1, 2006 and December 31, 2008, notwithstanding that the amended 2003 *Electric Utilities Act* had come into force a full year prior to the end of the period in question. No party in the proceeding leading to that decision (or in the proceeding and decision[135] to grant the review) objected to the process established by the Commission at the outset of that proceeding expressly calling for the Commission to make its determination for the entire 2006-2008 period based on the 2003 *Electric Utilities Act.*

4.4.2 The overlap between the 2003 and 2003/07 *Electric Utilities Act*

216. The 2003 *Electric Utilities Act* was amended effective January 1, 2008. One of the changes was the enactment of Section 20.2. It prescribed that the ISO must file with the Commission an ISO rule made under Section 20. However, Section 20.1 provides that sections 20.2 to 20.5 do not apply to an ISO rule that was made before those sections came into force on January 1, 2008.

217. Sections 20.3 to 20.5 of the 2003/07 *Electric Utilities Act* all relate to the ability of market participants to object to a non-expedited ISO rule before it takes effect. Section 20.1 therefore prevented any market participant, including Milner, from filing an objection to the amended Line Loss Rule (that was to take effect on January 1, 2009) had the ISO filed it with the

[135] AUC Decision 2013-159.

EUB (see paragraph 23 above). It also foreclosed any possible interpretation that Milner's 2005 "complaint" (which was made before the Line Loss Rule took effect) could be treated as an "objection" under the 2003/07 *Electric Utilities Act* once it came into force on January 1, 2008.

218. The Commission finds Section 20.1 to be significant for an additional reason. Relying on its plain and ordinary meaning, the Commission interprets Section 20.1 as stating that the objection provisions of the 2003/07 *Electric Utilities Act* cannot be relied upon by any market participant with respect to any ISO rule that (1) was in effect or (2) was made but not yet in effect, prior to January 1, 2008. The former is the case because any ISO rule in effect prior to January 1, 2008, by definition, must have been made prior to that date as well. What this means, in turn, is that the 2003/07 *Electric Utilities Act* is strictly forward looking in so far as the application of the objection provisions of the Act are concerned. The earliest date on which a notice of objection could have been filed by any market participant against an ISO rule would have been shortly after the ISO made (and filed under Section 20.2) its first rule following the coming into force of the 2003/07 *Electric Utilities Act.* In other words, the legislature, having created an enhanced public interest safeguard against the introduction of unlawful ISO rules (in the form of the objection provisions of the amended Act) expressly limited the protection afforded by this safeguard to ISO rules made after January 1, 2008.

219. The Commission, after careful consideration of the scheme of the 2003/07 *Electric Utilities Act* safeguards, also finds Section 25(1)(b) of that Act, the complaint provision, to be strictly prospective in its application. Unlike the complaint section in the 2003 *Electric Utilities Act* (that is, Section 25(1)(a)), the complaint provision of the 2003/07 *Electric Utilities Act* provides that complaints can only be made with respect to ISO rules that are "in effect." This qualification extends to and governs all related provisions of Section 25 (including Section 25(9)). The result is that prior complaints against ISO rules not yet in effect, such as Milner's 2005 complaint at the time it was filed, are not captured by any part of Section 25 of the 2003/07 *Electric Utilities Act.*

220. In reaching this conclusion, the Commission considered the following hypothetical scenario. Would the 2003/07 *Electric Utilities Act* apply to a complaint filed on December 31, 2007 with respect to a new ISO rule that was made on December 28, 2007, where the AESO notified the industry that the new rule would take effect on January 2, 2008? In considering this hypothetical scenario, the Commission first notes that both the proposed new rule and the complaint against the proposed new rule would have been made, and filed, respectively, under the provisions of the 2003 *Electric Utilities Act.* The amended legislation came into force on January 1, 2008. The Commission notes that, on that date, none of the provisions of Section 25 of the 2003/07 *Electric Utilities Act* could possibly have applied to the complaint. In particular, the December 31, 2007 complaint was clearly not a complaint "about an ISO rule that is in effect." Nor (given Section 20.1 of the 2003/07 *Electric Utilities Act*) could the December 31, 2007 complaint be interpreted, or be re-filed by the complainant as an "objection" against an ISO rule that was made but not in effect (even assuming that the ISO had filed its proposed rule with the Commission on January 1, 2008, something which it was clearly not required to do). In the circumstances of this hypothetical example, therefore, it must be the case that on January 1, 2008 the complaint continued to be governed by the 2003 *Electric Utilities Act*, notwithstanding that the amended legislation was already in force. Pursuant to this reasoning, it follows that nothing changed on January 2, 2008. Although the new ISO rule would have come into effect on that date (pursuant to the provisions of the 2003 *Electric Utilities Act*, since the 2003/07 *Electric Utilities Act* did not govern the effective date of the new rule), in the Commission's view that

fact alone could not have transformed the December 31, 2007 complaint about an ISO rule that was made but not yet in effect, into a complaint about an ISO rule "that is in effect."[136] Further reinforcing the Commission's finding that the 2003/07 *Electric Utilities Act* applies only prospectively both with respect to ISO rules and objections and complaints against ISO rules, is the fact that it avoids the following perverse outcome. Specifically, it avoids the conclusion that the legislature expressly intended that the amendments that were made by the ISO to its Line Loss Rule on November 8, 2007 (explained in paragraph 23 above) should be shielded from complaint from any source for a period of nearly 14 months until finally coming into effect on January 1, 2009. That is to say, because the amendments to the 2005 ISO rule were made in 2007 but were not intended to take effect until 2009, no market participant so inclined (Milner excluded, as its complaint continued unaffected) could file a complaint against the proposed amendments to the rule until January 1, 2009, at the very earliest. Moreover, no "objection" could *ever* be filed against the proposed amendments by the express terms of the 2003/07 *Electric Utilities Act*. Thus, unless the 2003 *Electric Utilities Act* continued to govern the proposed amendments to the Line Loss Rule until they took effect on January 1, 2009 and continued to allow for complaints to be made with respect those proposed amendments, the Commission is left with the following perverse conclusion: the legislature intentionally denied market participants the means to challenge a potentially unlawful ISO rule for a period of well over a year. If it is accepted that such a result was not intended by the legislature, then it must be the case that had a market participant filed a complaint under the 2003 *Electric Utilities Act* against the proposed amendments to the Line Loss Rule prior to those amendments taking effect, the remainder of the proceeding dealing with that complaint should also have been conducted pursuant to the terms of the 2003 *Electric Utilities Act*.

221. The Commission concludes that the provisions of the 2003 *Electric Utilities Act,* continue to govern the Commission's authority to provide relief as might be required to deal with the unlawful line loss charge components of the ISO tariff since January 1, 2006. The 2003/07 *Electric Utilities Act*, by its express terms, does not apply to the Milner complaint and does not expunge Milner's right to any remedy available under the 2003 *Electric Utilities Act* from the time Milner first filed its complaint under that Act.

4.4.3 Sections 36(1)(b) and 35(1)(c) of the *Interpretation Act* and the statutory scheme of the 2003 and 2003/07 *Electric Utilities Act*

222. Section 36(1)(b) of the *Interpretation Act*, R.S.A. 2000, c. I-8, provides as follows:

> 36(1) If an enactment is repealed and a new enactment is substituted for it,
>
> […]
>
> (b) every proceeding commenced under the repealed enactment shall be continued under and in conformity with the new enactment so far as may be consistent with the new enactment;

[136] It is unnecessary for the Commission to consider whether complaints made about a rule that was in effect before the amended Act came into effect and complained about after the rule was in effect would be governed under the 2003 or 2003/07 *Electric Utilities Act*. No such complaint is outstanding.

223. Although the Commission has duly considered all of the provisions of the *Interpretation Act* in determining which of the 2003 and 2003/07 *Electric Utilities Act* governs the remedies that might be available to the claimants in this proceeding, it has focused its attention primarily on sections 35(1)(c) and 36(1)(b). The Commission will first elaborate upon its reasoning with respect to Section 36(1)(b) of the *Interpretation Act*.

224. Placed in the context of this proceeding, Section 36(1)(b) of the *Interpretation Act* states that a proceeding commenced under the 2003 *Electric Utilities Act* shall be continued under and in conformity with the 2003/07 *Electric Utilities Act* "so far as may be consistent with the 2007 *Electric Utilities Act.*" The Commission has already found in the preceding section of this decision that the express wording of the 2003/07 *Electric Utilities Act* precludes the Commission from conducting its deliberations in Modules A to C of this proceeding under that version of the Act as neither the objection provisions nor the complaint provisions of the 2003/07 *Electric Utilities Act* (including Section 25(9)), have any application to the Milner complaint. The Commission finds further support for this finding when Section 36(1)(b) of the *Interpretation Act* is considered in light of the Commission's findings with respect to the overall statutory scheme of the 2003 and 2003/07 *Electric Utilities Act.*

225. The Commission examined in considerable detail the statutory schemes of the 2003 and 2003/07 *Electric Utilities Act* in Section 4.2 above and made a number of findings with respect to their overall purpose and design.

226. In view of these earlier findings and the express words of Section 36(1)(b) of the *Interpretation Act*, the Commission further finds that conducting or continuing the present proceeding under the 2003/07 *Electric Utilities Act* would not be consistent with the 2003/07 *Electric Utilities Act*. That version of the *Electric Utilities Act* expressly excludes the objection provisions from having any application in this proceeding. Those provisions were introduced at the same time and as part of a package of safeguards and constraints, including the important addition of Section 25(9). Therefore, even if the express wording of Section 25(1), which states that its application is limited to complaints against rules already *in effect,* is insufficient to preclude the 2003/07 *Electric Utilities Act* from applying to the Milner complaint, it would be fundamentally inconsistent with the 2003/07 *Electric Utilities Act* to have Section 25(9) apply to the circumstances of this proceeding without the complainants or, indeed any market participants, first having had an opportunity to avail themselves of the counterbalancing safeguards in the 2003/07 *Electric Utilities Act* against the ISO's introduction of the unlawful Line Loss Rule. It is the objection provisions of the 2003/07 *Electric Utilities Act* that provide the policy counter-balance to the express prohibition against retroactive rulemaking found in Section 25(9). To impose one without affording market participants, and the complainants in particular, the benefit of the other would result in a manifest injustice.[137] That injustice is not limited to the quantum that injured parties were compelled to pay in excess of what was just and

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[137] The Commission notes here that no similar injustice would befall a market participant that entered the industry after the objection period for any particular ISO rule had expired. While the new entrant would have no recourse to the objection provisions in the 2003/07 *Electric Utilities Act* against an ISO rule it might subsequently consider to be unlawful, there is no injustice in requiring the entrant to accept that its remedy, were the rule later found to be unlawful, may be constrained by section 25(9) of the 2003/07 *Electric Utilities Act*. The new entrant had a choice of whether or not to enter the market and must be considered to have known the rules in the market before it entered. Even then, a market participant can ask that it be exempted from the application of a rule.

reasonable. Not only did injured parties pay too much, other parties paid too little. The latter injustice is also at issue in this proceeding. In addition, all affected parties, whether those unjustly harmed or those unfairly rewarded, have something else in common. They were, and largely remain, active competitors of each other. To inflict financial harm without just cause on one group of competitors, while bestowing on another group of competitors financial benefits to which it has no just claim, is to interfere with the efficient market for electricity based on fair and open competition as required by Section 5 of the *Electric Utilities Act.*

227. Several of the parties, including AltaGas in particular, have looked to Section 35(1)(c) of the *Interpretation Act* for additional guidance in assessing which of the 2003 and 2003/07 *Electric Utilities Acts* should govern the Commission's determinations in Modules A to C of Phase 2 of this proceeding.[138]

228. Section 35(1)(c) of the *Interpretation Act* provides that:

> 35(1) When an enactment is repealed in whole or in part, the repeal does not
>
> […]
>
> (c) affect any right, privilege, obligation or liability acquired, accrued, accruing or incurred under the enactment so repealed;

229. What this provision states in the context of this proceeding is that the 2007 amendments to the 2003 *Electric Utilities Act* will not affect any right that may have been acquired by, or that has accrued or continues to accrue to Milner (or other claimants). This issue can be distilled to whether Milner's rights under the 2003 *Electric Utilities Act* have vested.

230. The unsettled state of the common law on the question of what constitutes a vested right is examined in considerable detail by Côté:

> To attempt a definition of "vested rights" would be somewhat audacious, if not actually rash.
>
> In the absence of clear definitions in the case law, how are litigants to determine, in a given situation, whether "vested rights" shield them from the application of new legislation?[139]

231. According to Côté, "analysis of the case law suggests that two considerations strongly influence judicial decisions": (1) the inconvenience and social costs of delaying the remedial effect of the new legislation and (2) the prejudice to individuals occasioned by the immediate application of the new statute. Côté goes on to state the following:

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[138] Exhibit 544.05, AltaGas Argument, September 24, 2014, pages 8-11, paragraphs 19-24; exhibit 545.01, TransAlta Argument, September 24, 2014, pages 8-9 and 13 paragraphs 42-43 and 55-57; exhibit 546.01, TCE Argument, September 24, 2014, page 10, paragraph 41; exhibit 548.01, ATCO Power Argument, September 24, 2014, pages 10 and 27, paragraphs 37 and 100; exhibit 553.01, ENMAX Argument, September 24, 2014, page 3, paragraph 12; exhibit 556.02, AltaGas Reply Argument, October 22, 2014, page 7, paragraph 17; exhibit 559.01, October 22, 2014, page 19, paragraphs 79-80; exhibit 560.01, ATCO Power, Reply Argument, October 22, 2014, page 24, paragraph 70.

[139] Côté, Pierre-André, The interpretation of legislation in Canada 4th edition Carswell, pages 167-168.

> [T]he perception of injustice by subjects of law is a critical element in decisions concerning the survival of previous statutes.
>
> It seems that judges, in ruling on the recognition of vested rights, implicitly weigh individual and social consequences. The greater the prejudice suffered by the individual, the greater are the chances that vested rights will be recognized…Conversely, where survival of the earlier statute is not viewed as a threat to the interests of society, the courts will find it easier to admit the existence of vested rights...[140]

232. The Commission is persuaded by Côté's proposition that protecting individuals from undue prejudice and avoiding perceptions of injustice are critical factors in determining whether the Milner complaint was sufficiently constituted to demonstrate a vested right before the effective date of the 2003/07 *Electric Utilities Act*, and in particular, Section 25 of that Act. The Commission concludes that by the time the 2003/07 *Electric Utilities Act* was in effect the Milner complaint was more than sufficiently detailed and supported by evidence to allow the Board or Commission to, in Côté's terminology, recognize Milner's right.[141] The Commission also finds implicit support for this conclusion in how the Alberta Court of Appeal describes Milner's right to complain as it stood in 2010. The possibility that Section 25(9) of the 2003/07 *Electric Utilities Act* might leave Milner without a remedy to which it was entitled under the 2003 *Electric Utilities Act* constitutes a risk of injustice to Milner (and other individual generators) further supporting a finding that its rights under the 2003 *Electric Utilities Act* had not been extinguished by the enactment of the 2003/07 *Electric Utilities Act*. For these reasons the Commission concludes that Milner is entitled to all relief available under the 2003 *Electric Utilities Act* for a complaint made out.[142]

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140 Côté, Pierre-André, The interpretation of legislation in Canada 4th edition Carswell, page 169.

141 Côté, Pierre-André, The interpretation of legislation in Canada 4th edition Carswell, page 299.

142 Exhibit 560.01, ATCO Power Reply Argument, October 22, 2014, page 28 paragraphs 80-81 states that "Alta Gas argues: "The law is clear that AUC's jurisdiction in relation to the Rule is governed by the current version of the EUA, and not any earlier one." ATCO Power submits that the consideration of the Milner Complaint should continue to be considered pursuant to the legislation that existed when the Milner Complaint was filed, just as the Commission has done in Decision 2014-110 in its determination that the Rule does not comply with the 2003 EUA… In support of its arguments regarding the applicability of the current version of the EUA, AltaGas spends many paragraphs making arguments about the "vesting" of rights. ATCO Power submits that the facts do not support the argument that Alta Gas is trying to make regarding "vesting". ATCO Power does not consider that the Commission is being asked to issue a remedy that was not available under the 2005 version of the EUA or that the current version of the EUA has taken away a remedy or right that was available, or that is being requested, under the previous legislation. While AltaGas appears to urge the Commission to consider the current version of the EUA because of its view that Section 25(9) therein allows that changes to ISO rules be made only on a prospective basis, the remedies available have not changed or been taken away, and in ATCO Power's respectful submission, the "vesting" arguments raised by AltaGas urging the Commission to consider the Milner Complaint under the current version of the EUA are misplaced." See also Exhibit 559.01, Milner Reply Argument, October 22, 2014, page 19-20, paragraphs 83-85 which states "[t]he principle to be derived from Blackstock, and similar cases is that rights vest where a party has taken steps by initiating proceedings, in an effort to assert a substantive right either through judicial, or quasi-judicial proceedings. This is precisely what Milner has done in the present case. Canadian courts have also been clear that they have a strong aversion to applying legislative changes, either directly or constructively, to extinguish entitlement to substantive rights during ongoing judicial or quasi-judicial proceedings. As Sullivan notes while referencing a number of Supreme Court of Canada decisions, "the courts dislike legislatures to intervene in on-going litigation". These principles dictate that the 2003 EUA applies to Milner's 2005 complaint."

4.4.4 The Commission's authority to provide a tariff-based remedy is unaffected by which of the 2003 and 2003/07 *Electric Utilities Act* governs this proceeding

233. The respondents, without exception, have argued that it is the 2003/07 *Electric Utilities Act* and not the 2003 *Electric Utilities Act* that must govern the Commission's determinations in Phase 2 of this proceeding with respect to the potential availability of a monetary remedy or relief on account of the unlawful ISO Line Loss Rule (and the unlawful line loss charges that flowed from it into the ISO tariff). All respondents also point to the fact that Section 25(9) of the 2003/07 *Electric Utilities Act* precludes changes to the Line Loss Rule on anything other than a prospective basis. However, there are significant differences amongst the respondents when it comes to the question of whether Section 25(9) of the 2003/07 *Electric Utilities Act* also precludes any retrospective tariff or rate-related remedy or relief on account of the unlawful line loss charges.

234. For example, the AESO and TransAlta argue that Section 25(9) of the 2003/07 *Electric Utilities Act* not only prohibits retroactive rulemaking but also bars retroactive ratemaking of any kind, over any time period, with respect to the line loss charge components of the ISO tariff. According to the AESO and TransAlta, this prohibition against retroactively changing the line loss components of the ISO tariff applies even where those rates have been made subject to an interim rate order. In their view, under no circumstances may line loss charges be altered retroactively once they have been approved in an ISO tariff proceeding. These respondents premise their argument on the following three propositions: (1) Section 25(9) of the 2003/07 *Electric Utilities Act* prohibits retroactive rulemaking; (2) the Line Loss Rule determines the line loss charge components in the ISO tariff; and (3) if the Line Loss Rule cannot be changed retroactively, then neither can the line loss charges and credits in the ISO tariff, since the latter depend on the former.[143]

235. The AESO elaborated on its position as follows:

> [T]he earliest that a change to the 2009 line loss rule directed by the Commission could become effective is the day on which the changed line loss rule is filed.
>
> …
>
> It follows, then, that the Commission cannot change the charges and credits for transmission line losses in an ISO tariff or order any form of financial compensation during [the] period [between the time a complaint is filed and the time a changed Line Loss Rule is filed], given that such charges and credits and compensation would have to be determined pursuant to an effective line loss rule.
>
> The AESO recognizes that, in Decision 2014-242, the Commission approved the 2013 and 2014 line loss component of the AESO's tariff on an interim basis. The AESO also recognizes that, as discussed above in section (D-F)(i), one instance in which retroactivity has been used in rate regulation is where interim rates have been set.
>
> However, in this case, as discussed above, section 25(9) of the EUA explicitly prohibits the retroactive application of an ISO rule. Therefore, even though the Commission approved the 2013 and 2014 line loss component of the AESO tariff on an interim basis, the AESO

[143] Exhibit 545.01, TransAlta Argument, September 24, 2014, page 13, paragraphs 58-59; and exhibit 557.01, TransAlta Reply Argument, October 22, 2014, paragraphs 7, 8, 16-18 and 37.

> submits that the Commission does not, in any event, have jurisdiction to change or replace an ISO rule retroactively during this time period.
>
> In other words, if the Commission orders the AESO to change the line loss rule, the changed rule cannot be the basis upon which the line loss component of the AESO's tariff can be amended, because, pursuant to section 25(9) of the EUA, the changed line loss rule cannot be effective retroactively during that period.[144]

236. The AESO sought further support for its argument that the line loss charges in the ISO tariff cannot be revised with retroactive effect in its interpretation of the scheme of the legislation and, in particular, in its interpretation of how the approval process for ISO rules differs from the approval process for the ISO tariff.

> In the AESO's respectful submission, the confusion regarding the relationship between the line loss rule and the AESO's tariff arises because the line loss rule and resulting loss factors are subject to a negative disallowance scheme, and are then used in the calculation of various rates included in the AESO's tariff, which is subject to a positive approval scheme.
>
> If the line loss rule and loss factors could be adjusted retroactively, this relationship would be problematic, as demonstrated in this case, where a complaint regarding the line loss rule is considered by the Commission after the loss factors have already been used to calculate rates in an AESO tariff that have been approved by the Commission. If the line loss rule and loss factors are subsequently adjusted retroactively (as is often done where a negative disallowance scheme is used), the AESO's tariff would also need to be adjusted retroactively. But this retroactive adjustment of the AESO's tariff would be inconsistent with the positive approval scheme to which the AESO's tariff is subject. In other words, if the Commission finds that it has jurisdiction to retroactively change the charges and credits collected under the AESO's tariff, an inconsistency would arise with respect to the approval scheme for the AESO's tariff as set out in Division 2 of Part 9 of the EUA.
>
> Accordingly, the relationship between the line loss rule and the AESO's tariff is only coherent and workable if charges and credits for transmission line losses cannot be adjusted retroactively. In other words, the only way in which the legislative scheme of the EUA can be interpreted to give effect to a coherent plan is to assume the Legislature did not intend for any charges or credits for transmission line losses to be changed retroactively, otherwise the approval scheme of the AESO's tariff will be undermined."[145]

237. The AESO then alluded to sections 25(6)(b) and 30(4) of the 2003/07 *Electric Utilities Act* in further support of its argument that the legislature intentionally denied the Commission the statutory authority to retroactively revise any part of the ISO tariff, even upon a determination having been made that the Line Loss Rule is unlawful. Section 30(4) of the 2003/07 *Electric Utilities Act* grants to the AESO the sole and discretionary authority to choose whether transmission line losses will be recovered by way of ISO fees or charges in the ISO tariff. Section 25(6)(b) of the 2003/07 *Electric Utilities Act*, meanwhile, authorizes the Commission to direct the ISO to reimburse a market participant any ISO fees it has paid if, after hearing a complaint about the ISO fee in question, the Commission finds that the fee was unjust and unreasonable. No comparable section exists in the rulemaking provisions of the Act authorizing

[144] Exhibit 547.01, AESO Argument, September 24, 2014, page 15.
[145] Exhibit 555.01, AESO Reply Argument, October 22, 2014, page 15.

the reimbursement to injured parties of the unlawful line loss charges they were required to pay under the ISO tariff. The AESO sees this as additional evidence of legislative intent that line loss charges cannot be altered retroactively. According to the AESO, its position:

> [I]s consistent with the implied exclusion rule, which, as explained in the AESO's argument, suggests that the Legislature intentionally chose not to give the Commission jurisdiction to order financial compensation for the costs of transmission line losses that the AESO recovered in its tariff. Indeed, it may be that the Legislature recognized the potential inconsistency between the approval schemes for the line loss rule and the AESO's tariff and that is why it chose not to give the Commission such jurisdiction.[146]

238. In the Commission's view, if the positions taken by the AESO and TransAlta in this proceeding were correct, the following perverse outcomes would ensue. That is, the coming into force on January 1, 2008 of Section 25(9) of the 2003/07 *Electric Utilities Act* had the effect of permanently denying any possibility of tariff-based monetary relief to any market participant suffering financial harm as a result of being forced to comply with the unlawful Line Loss Rule and unlawful line loss charges in the ISO tariff. This conclusion is unaffected by the magnitude or duration of harm suffered by those market participants that have been required to pay excessive line loss charges. Nor is this conclusion affected by the fact that other market participants have for many years unjustly benefited from unreasonably low line loss charges (as established by the Commission in Decisions 2012-104 and 2014-110). This conclusion is likewise unaffected by the fact that some market participants will continue to unjustly suffer financial harm, while other market participants will continue to unjustly benefit, until a new and legislatively compliant Line Loss Rule can be developed by the AESO, and be confirmed as such by the Commission, and just and reasonable line loss charges can be introduced into the ISO tariff. The Commission, moreover, understands these respondents to be saying that there is no action that can be taken presently, or that could have been taken in the past, by injured parties or the Commission that could lead, or could have led, to tariff-based monetary relief between January 1, 2008 and a yet unknown future date on which new line loss charges become part of the ISO tariff.[147] In the Commission's view, this is not a scenario or outcome that could possibly have been intended by the legislature. If it had been the legislature's intention, the legislature would have been explicit and amended the tariff provisions in the legislation at the same time, which it did not do.[148]

239. Although complex, the scheme of the ratemaking and rulemaking provisions of both the 2003 and 2003/07 *Electric Utilities Act* is rational, coherent and largely symmetrical. In particular, there is no conflict between the Commission's longstanding and well understood jurisdiction to ensure that rates are just and reasonable and the changes introduced by the

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146 Exhibit 555.01, AESO Reply Argument, October 22, 2014, page 4.

147 It should be observed, however, that the AESO has argued that the claimants could have applied to review and vary past ISO tariff decisions or sought leave to appeal them to the Court of Appeal. The Commission notes that neither of these two potential avenues of redress, even had the complainants pursued them successfully, would have led to compensation for harmed suffered prior to the date of the impugned tariff decision. This point is elaborated upon further at footnote 155 below.

148 The Commission likewise finds untenable the AESO's argument with respect to the import of Section 30(4) of both versions of the legislation. If the AESO's argument were correct, it would mean that the legislature had intended that the only entity capable of introducing a Line Loss Rule would also possess the sole discretion -- by virtue of its choice of collection mechanisms (i.e., ISO fees versus ISO rule-based tariffs) – to determine whether a remedy were available to injured parties should the rule prove to be unlawful.

legislature in the 2003/07 *Electric Utilities Act* expressly specifying when ISO rules, including changes to ISO rules arising from successful complaints, take effect.

240. The Commission bases, in part, the above finding that the legislature could not have intended to deny every possible avenue of retroactive or retrospective relief for parties harmed by an unlawful Line Loss Rule and the associated line loss components in the ISO tariff, on the following constituent, and closely linked, elements of the 2003 and 2003/07 *Acts* relating to rulemaking and ratemaking. First, the Commission observes that the legislature designed a coherent structure of safeguards and checks and balances in both versions of the *Electric Utilities Act* dealing with the treatment of and redress available to parties having unjustly suffered financial harm, whatever the circumstances leading to that harm. Safeguards under the 2003 *Electric Utilities Act* against the imposition of unlawful ISO fees or (where applicable) ISO-ordered administrative penalties for non-compliance with ISO rules and ISO fees, for example, were discussed by the Commission in paragraphs 92 - 93 above. The Commission addressed the corresponding safeguards under 2003/07 *Electric Utilities Act* in paragraphs 114 - 115 above. The significance of these safeguards, and why they appear in the rule (and fee) making provisions of the legislation while no comparable safeguards with respect to tariffed charges determined by the Line Loss Rule appear in the rulemaking provisions of the legislation, was addressed by the Commission in paragraphs 143 - 144 above. Second, although certain safeguards protecting market participants from the imposition of unlawful ISO rules were removed in the 2003/07 Act, they were replaced by even more robust safeguards, such as the introduction of the objection provisions in the 2003/07 *Electric Utilities Act*. Third, in enacting the amendments to the 2003 *Electric Utilities Act*, the legislature did not expressly preclude any available tariff-based remedies, notwithstanding that it did so with respect remedies for unlawful ISO rules. In the Commission's view, the enactment of Section 25(9) only governs the effective date for revised ISO rules. It does not change the Commission's legislative duty and authority to retroactively or retrospectively adjust the tariffed line loss charges flowing from the unlawful Line Loss Rule so that they are just, reasonable, not unduly, arbitrarily or unjustly discriminatory, and otherwise in compliance with the *Electric Utilities Act* and the *Transmission Regulation* - as required by the tariff provisions in Section 121 of the *Electric Utilities Act*.

241. Not all respondents in this proceeding argued that Section 25(9) of the 2003/07 *Electric Utilities Act* precludes every avenue of retroactive redress against unlawful line loss charges in the ISO tariff. In fact, several respondents have argued that had Milner or other aggrieved parties applied to the EUB (or later the Commission) for an order making interim the line loss charges and credits in the ISO tariff, the EUB (or Commission) would have possessed the requisite authority to alter those charges retroactively to the date of the interim order.

242. For example, ENMAX stated in its written argument that:

> Milner should have requested that the AESO's STS rates be approved on an interim basis, in order to preserve the Commission's ability to change those rates in the future in the event that Milner's complaint was ultimately successful.[149] [150]

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[149] Exhibit 542.01, ENMAX Argument, September 24, 2014, page 14, paragraph 42.

[150] The Commission notes that, in its reply argument, ENMAX reversed, or at least significantly stepped back from, its position cited above. In particular, ENMAX argued that Section 25(9) of the 2003/07 *Electric Utilities Act* dealing with ISO rules, in effect, overrides the Commission's well-established ratemaking authority to

243. AltaGas, in both its written argument and reply argument, has consistently claimed that had Milner sought, and successfully obtained, an order making line loss charges in the ISO tariff interim, the EUB (or Commission) would have possessed the requisite authority to retroactively change those rates. In addition, AltaGas (like the AESO) has suggested that it was also open to Milner and other parties to apply for review and variance of past Board and Commission decisions approving the line loss charges in the ISO tariff and/or to appeal such decisions through the courts. According to AltaGas:

> If Milner or any other market participant anticipated an issue with the Rule that could lead it to question an ISO tariff referring to one of these rules, they could have obtained interim approval of the relevant tariff components. To the same end, they could also have asked the Board or Commission to review and vary the tariff approvals in question, or sought leave to appeal the approval decisions to the Court of Appeal.[151]
>
> …
>
> With the exception of the 2013 and 2014 tariffs, in which line-loss charges were expressly approved on an interim basis, the Commission did not reserve its jurisdiction over past ISO tariffs and rates. Nor has any market participant initiated any proceeding challenging an ISO tariff (as distinct from an ISO rate, as demonstrated above), from which date the Commission could make its order. As a result, the Commission's jurisdiction over any tariffs prior to 2013 is exhausted and, following Coseka, it may not revisit those tariffs retroactively, irrespective of their justness or reasonableness.[152]

244. TransCanada has also stated that once the line loss charges in the ISO tariff were made interim (in Decision 2014-242), the Commission acquired the authority to revise the line loss charges in the ISO tariff retroactive to the date of the order.

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revisit and revise interim rates if they are subsequently determined to be unjust and unreasonable. According to ENMAX, if the Line Loss Rule cannot be changed retroactively, neither can the elements in the ISO tariff that derive from the rule. Thus, even where the impugned rates in the ISO tariff have been made interim, there is no statutory mechanism that allows for those rates to be changed retroactively without a linkage to the Line Loss Rule. At most, therefore, were the ISO Line Loss Rule to be revised by Commission order, the impugned rates may only be revised retroactively to the start of the year in which the rule was changed: "EEC understands that the Commission has approved the 2013 and 2014 line loss component of the AESO's tariff on an interim basis. Interim rates are an established exception to the rule against retroactive ratemaking, and those 2013 and 2014 rates are therefore subject to change. However, this does not change the fact that the Commission has no jurisdiction to retroactively change (or impose) an ISO Rule. This means that the 2014 line loss component of the AESO's tariff may be retroactively changed, but only if the Commission were to approve a new Line Loss Rule that came into effect in 2014." (Exhibit 553.01, ENMAX Reply Argument, October 22, 2014, page 7, paragraph 35.) The Commission further notes in this regard that in the proceeding leading to Decision 2014-242 in which, among other things, the Commission issued an order making interim the line loss charge component of the 2013-2014 ISO tariff based on the Commission's earlier determination in Decision 2014-110 that the Line Loss Rule was unlawful, ENMAX argued that the order should not be granted.

151 Exhibit 544.02, AltaGas Argument, September 24, 2014, page 24, paragraph 63, and page 43, paragraph 84. The Commission notes here that, contrary to AltaGas' suggestion, Milner did, in fact, attempt to intervene in the ISO's 2005-2006 GTA proceeding, but was unsuccessful. It also applied (without success) to the EUB for review and variance of Decision 2005-096 (which approved the ISO's 2005-2006 GTA). Milner likewise sought, but was denied, leave to appeal Decision 2005-096. The Commission further notes that, like the AESO, AltaGas offered no suggestions as to what grounds Milner or any other aggrieved party might have relied upon to pursue a review and variance application of an ISO tariff decision or leave to appeal such a decision if it were unable to introduce evidence at the tariff proceeding of the substantive basis for its complaint against the Line Loss Rule.

152 Exhibit 544.02, AltaGas Argument, September 24, 2014, page 26, paragraph 67.

> It is clear that the prohibition against retroactive rate-making is applicable in this case and therefore the Commission does not have jurisdiction to alter the charges that were made pursuant to approved final tariffs in the past. Where the line loss component of the tariff has been approved on an interim basis for 2013 and 2014, the Commission retains the ability to make changes in the rates and charges retroactively for that period.[153]

245. Capital Power likewise took the position that had Milner applied to have the line loss charges in the ISO tariff made interim (and been successful in doing so), the Board (or Commission, as applicable) would have had the authority to revise rates to the date of the order:

> [I]t must be remembered that Milner Power failed, for whatever reason, to pursue various avenues that could have improved its current situation.
>
> To name but one example, at no time has Milner Power sought to have the line loss charge components of the relevant AESO rates made interim. Instead, it was not until recently that any such request was made, and even then by ATCO Power rather than Milner Power.[154]

246. The Commission considers the above arguments, all of which were made by parties opposite in interest to Milner, to be significant for the following five reasons. First, if the Section 25(9) prohibition against retroactive *rulemaking* does not override the Commission's well established *ratemaking* authority to retroactively revise interim rates, including line loss charges in the ISO tariff, then it follows that other established exceptions to the general rule against retroactive ratemaking are likewise unaffected by Section 25(9) of the 2003/07 *Electric Utilities Act*. This includes, especially, the judicially recognized "knowledge" exception as well as that relating to negative disallowances schemes.

247. Second, if the positions taken on this issue by AltaGas, Capital Power, TransCanada and ENMAX (at least in its written argument) are correct, it follows that the Commission's authority to retroactively revise unlawful tariffed line loss charges does not depend on changing the Line Loss Rule retroactive to the date tariffed charges became interim. That is, it is possible for the Commission to retroactively adjust the tariffed charges without having to retroactively change the Line Loss Rule.

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153 Exhibit 546.01, TCE Argument, September 24, 2014, page 1, paragraph 2. The Commission notes that TransCanada takes a somewhat more qualified position later in its Argument (on the question of the Commission's authority to revise rates to the date they were made interim) relative to its statement above. See, for example, paragraphs 37, 40, 44, 53(e) and (f). In its reply argument, however, TransCanada was once again unequivocal in stating that: "…as already noted by Capital Power, there were other avenues available to Milner Power to preserve its rights, including by applying to the EUB and later the Commission to have the portion of the tariff collecting loss charges approved on an interim basis. The fact that it failed to protect its rights should not require the Commission to disregard its statutory and common law obligations relative to the AESO tariffs." (at exhibit 554.01, TCE Reply Argument, October 22, 2014, page 10, paragraph 38). This notwithstanding, TransCanada opposed ATCO's application (which was based on the outcome of Decision 2014-110) for an order making interim the line loss charge component of the 2013-2014 ISO tariff.

154 Exhibit 543.01, Capital Power Argument, September 24, 2014, page 14, paragraphs 64-65. The Commission notes that Capital Power also appears to suggest at paragraph 31 of its written argument that it was open to Milner or any other market participant to file an objection to the amended (2009) Line Loss Rule. As the Commission has already pointed out, however, that safeguard in the negative disallowance scheme applicable to ISO rules in the 2003/07 *Electric Utilities Act* was expressly denied to all market participants by virtue of the transitional provisions found in Section 20.1 of the amended legislation. The Commission also notes that in the proceeding leading to Decision 2014-242, Capital Power, like several other respondents, argued that an order making interim the line loss charge component of the ISO's 2013-2014 tariff should not be granted.

248. Third, the submissions of the above-noted respondents on whether Milner could, or should, have applied for an order making interim the line loss charge components of the ISO tariff, immediately raise the following question. That is, were Milner (or a similarly aggrieved party) to have made such an application, on what grounds could the requested order have been granted?[155] In the Commission's view ultimately, all potential grounds that might have supported the issuance of an interim rate order on any date between January 1, 2006 (the date the new ISO tariff took effect) and April 16, 2014 when the Commission issued Decision 2014-110, come down to the following. Namely, (1) a complaint had been made against the lawfulness of the ISO's Line Loss Rule pursuant to a statutorily established negative disallowance scheme and (2) the complaint expressly challenged not only the MLF/2 methodology pursuant to which line loss factors were calculated, but also raised serious concerns with respect to the financial impacts that would flow from the use of the impugned line loss factors in determining line loss charges and credits in the ISO's tariff.[156] Indeed, the complaint was filed about the rule in the 2005-2006 ISO tariff proceeding and the Board said the complaint would be dealt with in a complaint proceeding. Throughout the proceedings dealing with the Milner complaint, parties have made their arguments about the rule on the basis of the effects of changes to the amounts they would have to pay under the tariff if the rule were changed. Indeed, there would have been no reason for a complaint against the rule and no basis to resist the complaint against the rule if there had been no financial implications for the parties. It is clear to the Commission, as it appears to have

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155 The same question must also be asked in a related context. The AESO, for example, has argued that the only way to challenge an ISO tariff (or, presumably, any part thereof) is to apply to the Commission for review and variance of the ISO tariff decision or to obtain leave to appeal such a decision. (See exhibit 555.01, AESO Reply Argument, October 22, 2014, page 4). AltaGas likewise suggests that these remedies were always available to Milner and other aggrieved parties. However, neither the AESO nor AltaGas explain on what basis the Commission might have granted a review and variance application of an ISO tariff decision, or on what grounds the Court of Appeal might have granted leave to appeal such a decision, especially if the matter of the lawfulness of the Line Loss Rule (and, hence, the line loss charges that flow from it into the ISO tariff) had yet to be determined in a separate proceeding convened by the Commission for that purpose. The AESO, moreover, has argued that, in any event, the Commission should refrain from considering complaints about the ISO Line Loss Rule and line loss factors in any ISO tariff proceeding. (See exhibit 547.01, AESO Argument, September 24, 2014, page 3.) In these circumstances (i.e., in the absence of any evidence in an ISO tariff proceeding as to the lawfulness of the ISO Line Loss Rule or the line loss components in the ISO tariff) it is difficult for the Commission to envision how any review and variance application or application for leave to appeal, based on a claim that the impugned components of the ISO tariff were not just and reasonable, could ever have succeeded. Indeed, the Board itself in Decision 2005-150, and the Commission in Decision 2014-242, made clear that the proper forum for considering a Line Loss Rule complaint is not an ISO tariff proceeding but, rather, a separate complaint proceeding conducted pursuant to the rulemaking provisions of the governing legislation. This does not mean, however, as certain respondents (e.g., AltaGas) elsewhere suggest, that complaint proceedings with respect to an ISO Line Loss Rule cannot have tariff consequences. See paragraph 73.

156 Some of the respondents argue that because Milner's complaint was directed at the Line Loss Rule and not the line loss charge component of the ISO tariff, the Commission has no basis or authority to order compensation to injured parties, since no such authority can be found in the rulemaking provisions of the legislation. (See, for example, exhibit 544.02, AltaGas Argument, September 24, 2014, page 17, paragraph 44.) This notwithstanding, at least one respondent, TransAlta, acknowledges at paragraph 39 of its written argument "that Milner's concern is the financial implications of the application of the ISO Rule and resulting Loss Factor that would be used to calculate Rate STS, which would in turn be collected through the ISO tariff." The Commission is satisfied that although Milner's 2005 complaint was directed at first instance at the lawfulness of the ISO's Line Loss Rule, as would be expected of a complaint made pursuant to Section 25(1)(a) of the 2003 *Electric Utilities Act*, it is also the case, as evidenced by the words of the complaint itself, that Milner's ultimate concern was with the financial consequences it would suffer from the line loss charges that would invariably flow into the ISO tariff from the Line Loss Rule. See, for example, exhibit 2.01 Milner Complaint, August 17, 2005, paragraphs 31-33, 48-49, 59, 75, 89-94 and 99.

been clear to the Board and the parties throughout this proceeding that to complain about the Line Loss Rule is to complain about the ISO tariff.

249. The fact that final adjudication on the merits of the complaint had not yet taken place during this period (in the sense that all avenues of appeal from and reconsideration of the initial dismissal of the complaint by the EUB on December 30, 2005 had yet to be exhausted), means that the complaint was still very much a "live" issue between the date it was first filed with the Board and the respective dates on which the deadlines to appeal or seek review and variance of Decision 2014-110 expired.

250. Fourth, if the existence of a complaint against the Line Loss Rule provides insufficient basis to issue an order making interim the line loss charge component of the ISO tariff, only a single course of action remains open to the Commission in determining whether an interim rate order is warranted: to conduct the same type of inquiry that would have already commenced in respect of the lawfulness of the Line Loss Rule once the complaint was filed. Clearly, there would be no reason for the Commission to start a second, identical inquiry under the ratemaking provisions of the legislation. The reason these inquiries would be identical is that the sole purpose of the Line Loss Rule is to establish line loss factors that will determine charges for the recovery of line loss costs in the ISO tariff. What makes the Line Loss Rule lawful or unlawful, in turn, is whether the line loss factor calculation methodology associated with the rule complies with the applicable legislation and regulations in producing line loss factors. The lawfulness of the final transformation (by means of a simple mathematical calculation) of individual line loss factors into individual line loss charges or credits that flow into the ISO tariff is not, and has never been, in dispute in the long history of this or any related proceeding dealing with Milner's complaint.[157] Accordingly, a Line Loss Rule and line loss factors that comply with applicable legislation and regulations will also produce line loss charges that comply with applicable legislation and regulations. The opposite will also hold true.

251. Fifth, given (1) the Commission's earlier finding in this proceeding that the approval process for the ISO tariff, including the line loss charge component thereof, is by its very nature a negative disallowance scheme, and (2) the well-established common law exceptions to the rule against retroactive ratemaking for negative disallowance schemes and situations in which affected parties knew or ought to have known that rates were subject to change, the Commission finds that it was unnecessary for Milner or any other aggrieved party to apply for an order making interim the line loss charge component of the ISO tariff once the 2005 complaint had been filed. The complaint itself provides the Commission with the necessary authority to revisit the justness and reasonableness of the line loss charge component of the ISO tariff to the date the rates in question first came into effect.

[157] The relationship between the ISO Line Loss Rule, line loss factors produced by that rule, tariffed Supply Transmission Service (Rate STS) and charges under Rate STS is described in the ISO tariff as follows: "2(1) The charge under Rate STS in a settlement period will be the losses charge calculated as the sum, over all hours in the settlement period, of metered energy in the hour multiplied by pool price multiplied by a loss factor for the facility, where the loss factor is determined in accordance with ISO rule 9.2 and is available to market participants in the loss factors section of the ISO website." (http://www.aeso.ca/downloads/AESO_2013_ISO_Tariff_(2015-01-01).pdf) Similar provisions exist in the ISO tariff with respect to the rates for Rate DOS, Rate XOS and Rate IOS. See, exhibit 548.01, ATCO Power Argument, September 24, 2014, paragraph 19.

252. As the jurisprudence relating to ratemaking in the context of negative disallowance schemes makes clear (in so far as is applicable to the present proceeding), the result of a successful complaint against an ISO rule that bears upon the ISO tariff is that earlier-approved rates determined under the ISO rule effectively become interim from the date of the complaint. That is to say, the courts have allowed rates to be adjusted to the time a successful complaint was first filed against rates initially given effect pursuant to a negative disallowance scheme.

253. The Commission relies on this ratemaking principle in finding that Section 25(9) of the rulemaking provisions of the 2003/07 *Electric Utilities Act* does not preclude the Commission from adjusting rates with retroactive effect pursuant to its ratemaking powers. The Commission also finds, in this regard, that because it is charged with the responsibility of ensuring that rates are just and reasonable during the entire period such rates are deemed by operation of law to be interim, the process of calculating or determining rates that meet this standard does not require that a new or changed Line Loss Rule be put into effect during the period throughout which unlawful rates were imposed in the first instance.[158] In this proceeding, the Commission has found that the Line Loss Rule produced and continues to produce line loss charges that are unjust and unreasonable and that are contrary to the legislation and regulations. Those impugned rates, by operation of the statutorily imposed negative disallowance scheme, must now be treated as, in effect, being interim in nature. In such circumstances, as with similar situations where the Commission is called upon to adjust interim rates, the Commission can have recourse to any information it deems necessary or relevant from the tariff applicant or interveners in setting final tariff rates that meet the test of justness and reasonableness.[159]

254. What this means in the present context is that it is not strictly necessary for the Commission, in determining what line loss tariff charges would be just and reasonable for parties harmed by (or unjustly benefitting from) unlawful line loss charges, to rely exclusively on the line loss factors (and associated line loss charges) produced by a new or changed ISO Line Loss Rule as the benchmark against which to make this determination. In other words, in the Commission's view, there is no *a priori* reason to assume that what was, or would have been, just and reasonable, from January 1, 2006 to the date future line loss charges come into effect must be identical to those future line loss charges.

255. The Supreme Court in the *Nova* case implicitly recognized this very point.

> The second result is that Nova is free upon the expiry of the order at the end of 1978 to establish, once again, whatever rates it may wish to recover from its customers; subject of course to the right in an interested party to file a complaint, as indeed was done here by the producers.[160]

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158 As the previous discussion has shown, AltaGas, TransCanada, Capital Power and ENMAX (at least in its written argument), not to mention the complainants, are also uniformly of the view that the Commission's authority to retroactively revise interim rates is not affected by Section 25(9) of the 2003/07 *Electric Utilities Act*, which requires that a new or changed ISO Line Loss Rule can only come into effect on a prospective basis.

159 The Commission's authority in this regard was referred to by Côté JA in the *ATCO Costs* case (at paragraph 146) as a well-established rule of law. According to Côté JA: "The Commission is not limited to acting on evidence formally put before it by the utility company or an intervener; it can gather information spontaneously, by its own staff: ***Northwestern Utilities v Edmonton (City)*** [1929] SCR 186, [1929] 2 DLR 4, 8-9."

160 *Nova*, page 451.

256. In other words, the court recognized that Nova faced no statutory compulsion to maintain the same rates going forward as had been put into effect by the Public Utilities Board once the 12-month Board order varying rates had expired. The new rates would be presumed to be just and reasonable – notwithstanding that they could differ from the previous rates the Public Utilities Board had temporarily put in place to remedy the previously unjust and unreasonable rates – unless and until found to be otherwise upon complaint.

257. The Commission finds additional support for its findings with respect to the effect of Section 25(9) of the 2003/07 *Electric Utilities Act* in another of the key changes introduced by the legislature in the 2003/07 *Electric Utilities Act*, namely, the new test to be met by market participants when filing a complaint against an ISO rule. Under the 2003 *Electric Utilities Act*, complainants were required to demonstrate that the impugned ISO rule failed to meet the standards required of a tariff (i.e., those found in Section 121 of the 2003 *Electric Utilities Act* and repeated in Section 25(6)(b) of the 2003 *Electric Utilities Act*). Under Section 25(4.1) of the 2003/07 *Electric Utilities Act*, by comparison, complainants now bear the onus of proving "(a) that the ISO rule is technically deficient, (b) that the ISO rule does not support the fair, efficient and openly competitive operation of the market, or (c) that the ISO rule is not in the public interest."

258. In the Commission's view, the new test more closely follows the language of, and better aligns with the concepts embodied in, the fair, efficient and openly competitive standard set out (identically) in Section 5 of both versions of the *Electric Utilities Act*. That section defines the purposes of the *Electric Utilities Act*. The Commission considers this new test of the factual and legal threshold to be met by a market participant seeking to have an ISO rule changed or disallowed to be better suited to technical and operational rules than the traditional "just and reasonable" tariff test. The latter is more difficult to apply to purely technical standards and specifications (especially where there is no monetary component) than it is to rates being charged to market participants to recover a variety of costs and expenses, including the costs of line losses attributable to them. What is significant about this observation is that while the legislature enacted in the 2003/07 *Electric Utilities Act* a completely new test to be met in challenging all ISO rules, it left entirely intact the corresponding Section 121(2) test to be met in determining the lawfulness of all tariffs, including the ISO tariff and the line loss charges included therein. This suggests that it was not the legislature's intention to alter the well-established jurisprudence governing ratemaking.

259. Finally, the Commission remains sensitive to the following concern expressed by the courts. That is, the overall scheme of legislation governing regulatory ratemaking should not be interpreted in a manner that creates incentives for parties to act opportunistically where a finding has been made that existing rates are unjust and unreasonable. In particular, in so far as negative disallowance schemes are concerned, it would run contrary to the very purpose of such schemes were it possible for parties that benefit from unjust and unreasonable rates to permanently (and unjustly) capture for their benefit, at the expense of injured parties, the rewards attending regulatory delay. As stated by Laycraft J.A. for a unanimous Alberta Court of Appeal in *Coseka* (where the issue turned on whether interim rates could be revised with retroactive effect):

> When the parties to a hearing realize that the rates set in an interim order are subject to variation, they will perceive that there is no advantage to be gained by delay.
>
> I am constrained to observe that protestations by Coseka of injustice arising from long delay have a hollow ring in this case. Coseka refused to come before the Board or to assist it on

> Husky's appeal from the APMC decision when the Board sought to determine the position of Saratoga's costs attributed to Savanna Creek gas. It sought by legal action to prevent the Board from acting on the first order in council to finalize the interim order. It gave every appearance of being reluctant to find itself before the Board. An officer of the Company was frank to explain the reason for this attitude in answer to questions from a Board member who pointed out that Coseka had refused to assist the Board and had withdrawn from the hearings. The following then appears in the transcript of the hearing:
>
> Q I see, and that's what concerns me. I'm sure you're a very astute businessman, Mr. Kutney, and since you were being so badly treated, you knew this Board may be of some assistance, you knew you were a party to these proceedings, yet you didn't wish to give it. What happened to your practical considerations then?
>
> A I guess there was some more that entered into that judgment possibly the business considerations, <u>the longer we stayed away from this Board, maybe the longer the favourable rate would stay in effect!</u>[161]

260. In the present circumstances, if no mechanism exists to revisit and revise rates found to be unjust and unreasonable (at least under the 2003/07 *Electric Utilities Act*), as some respondents argue, there is every incentive to delay for as long as possible the introduction of new line loss charges that would remove this benefit, if only on a going-forward basis.

261. For all of the reasons provided in this decision, the Commission finds the positions taken by the AESO and TransAlta that no mechanism exists to revisit and retroactively or retrospectively revise rates found to be unjust and unreasonable are contrary to the overall scheme and purpose of the legislation as well as the intention of the legislature.

Conclusion

262. The Commission finds that the 2003 *Electric Utilities Act* governs its determinations in this proceeding for all of the reasons provided above. The Commission also finds that it has the authority to order a remedy or relief to correct for the payment or receipt of unlawful line loss charges and credits included in the ISO tariff from January 1, 2006 to the date a new rule goes into effect. This authority is independent of which version of the *Electric Utilities Act* governs this proceeding, for two reasons. First, in so far as is relevant to this proceeding, the Commission's ratemaking authority is substantially the same under both the 2003 *Electric Utilities Act* and 2003/07 *Electric Utilities Act.* Second, the Commission's authority to provide tariff-related relief on a retrospective basis is not affected by the rulemaking provisions of either version of the *Electric Utilities Act* and, in particular, by Section 25(9) of the 2003/07 *Electric Utilities Act.* Thus, even if the provisions of the 2003/07 *Electric Utilities Act* were to govern the Commission's authority to order a remedy or relief to correct for the payment or receipt of unlawful line loss charges and credits included in the ISO tariff from January 1, 2006 to the date a new rule goes into effect, the outcome would still be the same.

263. After carefully examining the statutory scheme of both the 2003 *Electric Utilities Act* and the 2003/07 *Electric Utilities Act*, the Commission is unable to conclude that the design and purpose of either version of the legislation is such that the availability and quantum of any monetary relief that might otherwise be granted to an injured party, are in any way restricted by

[161] *Coseka*, at paragraph 36-37.

the amount of time that has expired since Milner filed its original complaint. Having determined that monetary relief is both necessary and just, and that the Commission possesses the requisite authority to grant such relief, the Commission further determines that such relief as may be granted will be granted for the period January 1, 2006 (the date the unlawful Line Loss Rule and associated line loss charges in the ISO tariff first came into effect) to the date a new rule takes effect.

264. If it is necessary for the Commission to rule on the complaint against the Line Loss Rule filed by Milner on June 11, 2012 and the complaint against the Line Loss Rule filed by ATCO Power on July 30, 2012, the Commission finds that the complaints, insofar as they relate to the lawfulness of the MLF/2 methodology included in the Line Loss Rule, have been made out. No party to this proceeding argued otherwise.

265. In Decision 2014-242: *2014 ISO Tariff Application and 2013 ISO Tariff Update*, the Commission approved the line loss charge components of the ISO tariff on an interim basis. The Commission did so based on the evidence and arguments before it in that proceeding. The Commission finds in this decision, that while the decision to make a portion of the ISO tariff interim was correct based on the evidence and application filed, it was unnecessary for the Commission to do so because the line loss charge components of the ISO tariff have been effectively interim since January 1, 2006.

5 Order

266. The Commission, following hearings in Modules B and C, will proceed to determine the relief and remedies to be granted in accordance with its findings and conclusions regarding its authority and jurisdiction made in this decision.

Dated on January 20, 2015.

Alberta Utilities Commission

(*original signed by*)

Willie Grieve, QC
Chair

(*original signed by*)

Neil Jamieson
Commission Member

(*original signed by*)

Bohdan (Don) Romaniuk
Acting Commission Member

Appendix 1: Proceeding participants

Name of organization (abbreviation) counsel or representative
Alberta Direct Connect Consumers Association (ADC) Colette Chekerda
Alberta Electric System Operator (AESO) David Holgate – Stikeman Elliott LLP
AltaGas Ltd. (AltaGas) Jonathan Liteplo – Fasken Martineau Dumoulin LLP.
ATCO Power Ltd. (ATCO Power) Marie Buchinski – Bennett Jones LLP
Capital Power Corporation (Capital Power) Douglas Crowther – Dentons Canada LLP
Encana Corporation (Encana) Rosa Twyman – Regulatory Law Chambers LLP
ENMAX Energy Corporation (ENMAX) David Wood – Torys LLP
Industrial Power Consumers Association of Alberta (IPCAA) Sheldon Fulton
Milner Power Inc. (Milner) Monte Forster
Powerex Corp. (Powerex) Chris Sanderson - Lawson Lundell LLP
TransAlta Corporation (TransAlta) Laura-Marie Berg
TransCanada Energy Ltd. (TransCanada) Nadine Berge

Alberta Utilities Commission

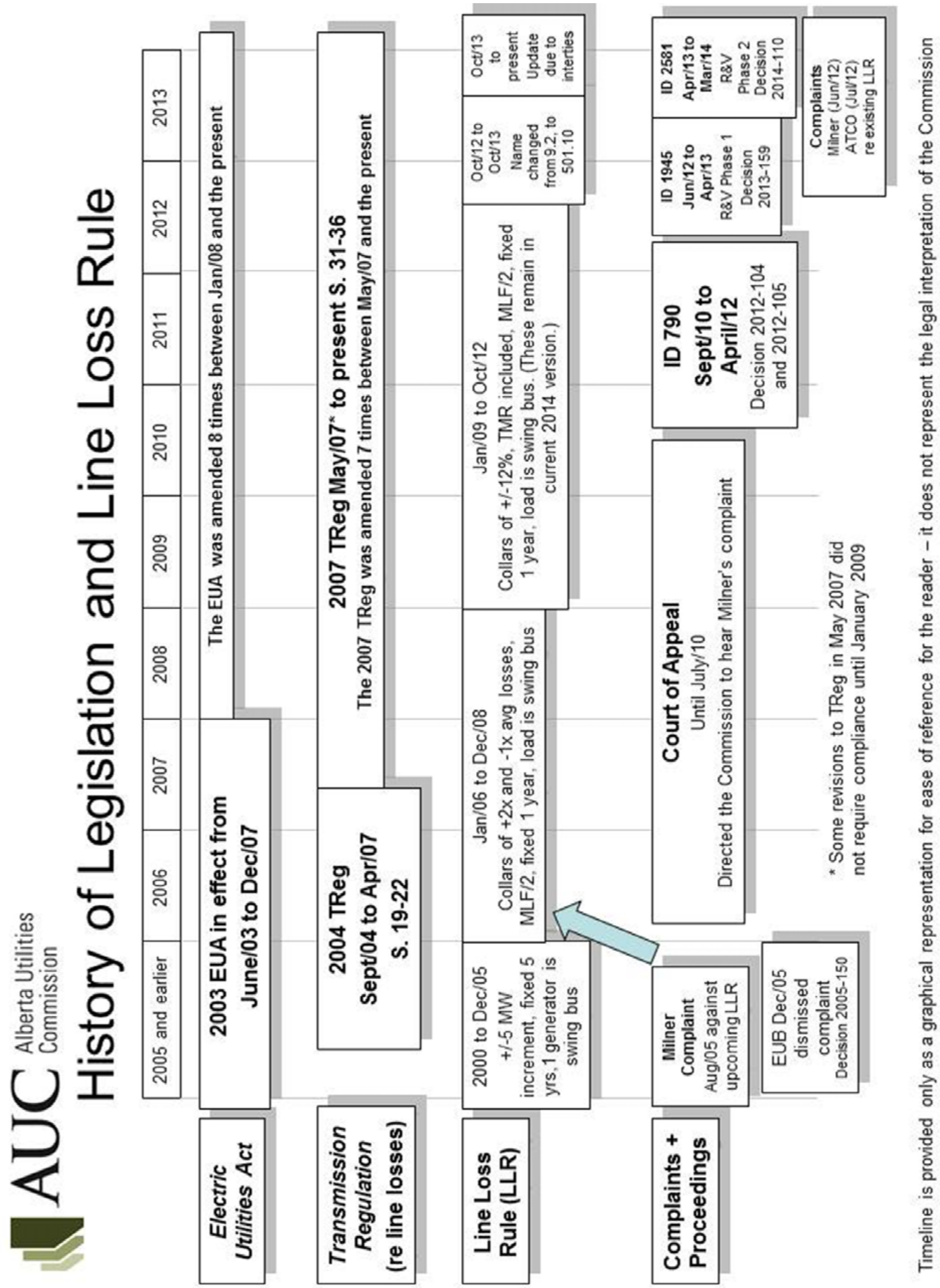
Commission Panel
W. Grieve, QC, Chair
N. Jamieson, Commission Member
B. Romaniuk, Acting Commission Member

Commission Staff
J. Petch, QC (Commission Counsel)
A. Davison (Senior Market Analyst)
G. Andrews (Market Analyst)

Appendix 2: Abbreviations

Abbreviation	**Name in Full**
AESO	Alberta Electric System Operator
ATCO Power	ATCO Power Ltd.
AltaGas	AltaGas Ltd.
AUC or the Commission	Alberta Utilities Commission
Capital Power	Capital Power Corporation
The claimants	Milner Power Inc., ATCO Power Ltd. and Powerex Corp.
Collars	Limits imposed by various version of the *Transmission Regulation*
CRTC	Canadian Radio-television and Telecommunications Commission
ENMAX	ENMAX Energy Corporation
EUB or the Board	Alberta Energy and Utilities Board
FEOC	Fair, Efficient and Openly Competitive
GTA	General Tariff Application
IPCAA	Industrial Power Consumers Association of Alberta
ISO	Independent System Operator
Line Loss Rule	ISO rule 9.2: *Transmission Loss Factors* and Appendix 7: *Transmission Loss Factor Methodology and Assumptions*
Milner	Milner Power Inc.
MLF/2	Marginal loss factor divide by two
Powerex	Powerex Corp.
The respondents	Alberta Electric System Operator, Alta Gas Ltd., Capital Power Corporation, ENMAX Energy Corporation, TransAlta Corporation and TransCanada Energy Ltd.
TransAlta	TransAlta Corporation
TransCanada	TransCanada Energy Ltd.
Rate STS	Supply Transmission Service
Rate DOS	Demand Opportunity Service
Rate IOS	Import Opportunity Service
Rate XOS	Export Opportunity Service

Appendix 3: History of legislation and Line Loss Rule



Appendix 4: Sections of relevant legislation

***Electric Utilities Act*, SA 2003, c E-5.1**

…

5 The purposes of this Act are

(a) to provide an efficient Alberta electric industry structure including independent, separate corporations to carry out the responsibilities of the Independent System Operator, the Market Surveillance Administrator and the Balancing Pool, and to set out the powers and duties of those corporations;

(b) to provide for a competitive power pool so that an efficient market for electricity based on fair and open competition can develop, where all persons wishing to exchange electric energy through the power pool may do so on non-discriminatory terms and may make financial arrangements to manage financial risk associated with the pool price;

(c) to provide for rules so that an efficient market for electricity based on fair and open competition can develop in which neither the market nor the structure of the Alberta electric industry is distorted by unfair advantages of government-owned participants or any other participant;

(d) to continue a flexible framework so that decisions of the electric industry about the need for and investment in generation of electricity are guided by competitive market forces;

(e) to enable customers to choose from a range of services in the Alberta electric industry, including a flow-through of pool price and other options developed by a competitive market, and to receive satisfactory service;

(f) to continue the sharing, among all customers of electricity in Alberta, of the benefits and costs associated with the Balancing Pool;

(g) to continue the framework established for power purchase arrangements;

(h) to provide for a framework so that the Alberta electric industry can, where necessary, be effectively regulated in a manner that minimizes the cost of regulation and provides incentives for efficiency.

…

17 The Independent System Operator has the following duties:

(e) to manage and recover the costs of transmission line losses;

...

20(1) The Independent System Operator may make rules respecting

(a) the practices and procedures of the Independent System Operator;

(b) the operation of the power pool and the exchange of electric energy through the power pool;

(c) the operation of the interconnected electric system;

(d) the provision of ancillary services;

(e) planning the transmission system, including criteria and standards for the reliability and adequacy of the transmission system;

(f) the processes for expansion and enhancement of the transmission system;

(g) the procedures to be observed in emergencies relating to the operation of the interconnected electric system;

(h) load settlement, including

(i) the conduct of load settlement by market participants;

(ii) the establishment of processes, procedures, standards, reports and controls required to determine the hourly allocation of electric energy to sites and to customers;

(iii) the determination, collection and storage of site, customer, metering and other data in order to provide necessary measurement data;

(iv) the development and use of customer load profiles to determine the hourly allocation of electric energy to sites that do not have interval meters;

(v) the transfer of data among market participants;

(vi) approval of professional and other costs relating to the development and implementation of the rules and by whom the costs are to be paid;

(vii) incentives for efficient performance of load settlement;

(i) direct sales agreements and forward contracts as defined in section 19(1);

(j) the granting of exemptions from the rules, and setting out the process for obtaining an exemption;

(k) procedures for resolving disputes between the Independent System Operator and market participants, which may include arbitration under the Arbitration Act;

(l) any other matter the Independent System Operator considers necessary or advisable to carry out its duties, responsibilities and functions under this Act and the regulations.

(2) The Independent System Operator must make its rules available to the public except for those rules that the Independent System Operator considers not to be in the public interest to disclose publicly, in which case an explanation for the non-disclosure of those rules must be given.

(3) A market participant must comply with ISO rules.

…

21(1) The Independent System Operator must establish and charge fees payable by market participants

(a) for the exchange of electric energy through the power pool,

(b) to pay for the aggregate expenditures, costs and expenses shown in the approved budget of the Market Surveillance Administrator and any approved amendment to the budget, and

(c) to pay for the costs and expenses of other powers, duties, responsibilities and functions of the Independent System Operator, except costs and expenses recovered under the ISO tariff.

(2) The fees must be just and reasonable and may be varied from time to time.

(3) A market participant who is charged a fee by the Independent System Operator must pay the fee.

(4) A market participant charged a fee by the Independent System Operator may make a complaint to the Board under section 25.

(5) A fee charged by the Independent System Operator is a debt owing by the market participant to the Independent System Operator and in default of payment may be recovered by the Independent System Operator by an action in debt.

(6) The Independent System Operator must maintain a current schedule of its fees and make the schedule available to the public.

22(1) If the Independent System Operator is satisfied that a market participant has contravened an ISO rule or failed to pay an ISO fee, the Independent System Operator may, by order, do one or more of the following:

(a) impose an administrative penalty on the market participant of not more than $100 000 a day for each day on which a contravention occurs or continues;

(b) deny, suspend, restrict or terminate the right of a market participant to exchange electric energy through the power pool or to participate in any other market operated by the Independent System Operator;

(c) impose another sanction that the Independent System Operator considers appropriate;

(d) order compliance with the ISO rule or payment of an ISO fee.

(2) When making an order, the Independent System Operator may take into consideration any failure or refusal of a market participant to co-operate with the Independent System Operator.

(3) A market participant who is the subject of an ISO order may make a complaint to the Board under section 25.

(4) An administrative penalty imposed by the Independent System Operator must be paid to the Balancing Pool.

(5) The Independent System Operator must establish and maintain a current schedule of administrative penalties that it may impose and make the schedule available to the public.

23(1) Subject to the right to make a complaint under section 25, if a person fails to pay an administrative penalty in accordance with the order imposing it, the Independent System Operator may file a copy of the order with the clerk of the Court of Queen's Bench, and on being filed, the order has the same force and effect and may be enforced by the Independent System Operator as if it were a judgment or order of the Court.

(2) Subject to the right to make a complaint under section 25, the Independent System Operator may apply to the Court of Queen's Bench to enforce an ISO order, other than an order to pay an administrative penalty, on giving notice of the application to the person against whom enforcement is sought, in accordance with the Alberta Rules of Court.

(3) An application under subsection (2) must be accompanied with the original ISO order or a certified copy of it.

(4) The Court of Queen's Bench may give judgment enforcing an ISO order unless

(a) the order is the subject of complaint under section 25 that has not been decided,

(b) the order is the subject of judicial proceedings that put it in question, or

(c) the order is not capable of enforcement in law.

25(1) Any person may make a written complaint to the Board about

(a) an ISO rule,

(b) an ISO fee, or

(c) an ISO order.

(2) A complaint about an ISO fee or an ISO order must be made within 60 days of the date the market participant receives notice of the fee or order.

(3) Before dealing with any complaint, the Board may require the person making the complaint and the Independent System Operator to attempt to negotiate a settlement of the matter or participate in a dispute resolution process selected by the Board.

(4) The Board may, by giving written notice with reasons to the person making the complaint, decline to investigate a matter or hold a hearing, or terminate an investigation or hearing, if the Board considers

(a) the complaint is frivolous, vexatious, trivial or otherwise does not warrant investigation or a hearing;

(b) the complaint or the substance of it has been referred to, should be referred to, or is the subject of an investigation by, the Market Surveillance Administrator;

(c) the complaint or the substance of it has been investigated by the Market Surveillance Administrator, has been the subject of a tribunal hearing or has been the subject of a tribunal order;

(d) the subject-matter of the complaint is under the jurisdiction of another authority.

(5) Unless the Board otherwise orders, a complaint under this section does not relieve the person making the complaint from the obligation

(a) to pay an ISO fee pending a decision of the Board, or

(b) to comply with an ISO order or ISO rule pending a decision of the Board.

(6) If the Board decides to hear the complaint, the Board may, by written decision giving reasons,

(a) determine the justness and reasonableness of

(i) an ISO fee, or

(ii) an ISO order and may confirm, change or revoke the fee or order;

(b) order the Independent System Operator to revoke or change a provision of an ISO rule that, in the Board's opinion, is unjust, unreasonable, unduly preferential, arbitrarily or unjustly discriminatory or inconsistent with or in contravention of this Act or the regulations;

(c) dismiss the complaint;

(d) direct the Independent System Operator to reimburse a market participant any fee paid to the Independent System Operator;

(e) direct the Balancing Pool to reimburse a market participant any administrative penalty paid to the Balancing Pool in accordance with an ISO order.

…

30(1) The Independent System Operator must submit to the Board, for approval under Part 9, a single tariff setting out

(a) the rates to be charged by the Independent System Operator for each class of system access service, and

(b) the terms and conditions that apply to each class of system access service provided by the Independent System Operator to persons connected to the transmission system.

(2) The rates to be charged by the Independent System Operator for each class of service must reflect the prudent costs that are reasonably attributable to each class of system access service provided by the Independent System Operator, and the rates must

(a) be sufficient to recover

(i) the amounts to be paid under the approved tariff of the owner of each transmission facility,

(ii) the amounts to be paid to the owner of a generating unit in circumstances in which the Independent System Operator directs that a generating unit must continue to operate, and the costs to make prudent arrangements to manage the financial risk associated with those amounts,

(iii) farm transmission costs, and

(iv) any other prudent costs and expenses the Board considers appropriate,

(b) either be sufficient to recover the annualized amount paid to the Balancing Pool under section 82(7), or if the Independent System Operator receives an annualized amount under section 82(7), reflect that amount, and

(c) include any other costs, expenses and revenue determined in accordance with the regulations made by the Minister under section 99.

(3) The rates set out in the tariff

(a) shall not be different for owners of electric distribution systems, customers who are industrial systems or a person who has made an arrangement under section 101(2) as a result of the location of those systems or persons on the transmission system, and

(b) are not unjust or unreasonable simply because they comply with clause (a).

(4) The Independent System Operator may recover the costs of transmission line losses and the costs of arranging provision of ancillary services acquired from market participants by

(a) including either or both of those costs in the tariff, in addition to the amounts and costs described in subsection (2), in which case the Board must include in the tariff the additional costs it considers to be prudent, or

(b) establishing and charging ISO fees for either or both of those costs.

…

119(4) The Independent System Operator must prepare a tariff relating to the transmission system in accordance with Part 2 and apply to the Board for approval of the tariff.

…

121(1) On giving notice to interested parties, the Board must consider each tariff application.

(2) When considering whether to approve a tariff application the Board must ensure that

(a) the tariff is just and reasonable,

(b) the tariff is not unduly preferential, arbitrarily or unjustly discriminatory or inconsistent with or in contravention of this or any other enactment or any law, and

(c) if the regulations so require, the tariff incorporates the standard of liability imposed by the regulations made by the Lieutenant Governor in Council under section 94, or that the Board has, in accordance with those regulations, considered and imposed a standard of legal liability that it considers appropriate.

(3) A tariff that provides incentives for efficiency is not unjust or unreasonable simply because it provides those incentives.

(4) The burden of proof to show that a tariff is just and reasonable is on the person seeking approval of the tariff.

***Electric Utilities Act*, SA 2003/07, c E-5.1**

...

20.1 Sections 20.2 to 20.5 do not apply to an ISO rule

(a) that was made before the coming into force of those sections, or

(b) that takes effect in accordance with section 20.6.

20.2(1) The Independent System Operator must file with the Commission an ISO rule made under section 19 or 20.

(2) The Commission must publish notice of the filing of an ISO rule under subsection (1) not later than 5 days after the day of filing.

(3) Subject to subsection (4), a notice under subsection (2) must include a copy of the ISO rule or set out where a copy may be obtained.

(4) If the Commission is satisfied on information provided by the Independent System Operator that it would not be in the public interest for an ISO rule to be available to the public, the notice under subsection (2) must contain a summary of the ISO rule and explain why a copy of the ISO rule is not included.

…

20.4(1) A market participant may object to an ISO rule that is filed under section 20.2 on one or more of the following grounds:

(a) that the Independent System Operator, in making the ISO rule, did not comply with Commission rules made under section 20.9;

(b) that the ISO rule is technically deficient;

(c) that the ISO rule does not support the fair, efficient and openly competitive operation of the market;

(d) that the ISO rule is not in the public interest.

…

20.6(1) If, in the opinion of the Independent System Operator, a matter that is addressed in an ISO rule is urgent or there are other sufficient reasons that require that the ISO rule take effect expeditiously, the Independent System Operator may specify in the ISO rule that it takes effect in accordance with this section.

(2) The Independent System Operator must file an ISO rule referred to in subsection (1) with the Commission.

(3) An ISO rule that is filed under subsection (2) takes effect on the later of the day on which it is filed and the day specified in the ISO rule.

(4) The Commission must publish notice of an ISO rule that is filed under subsection (2) as soon as possible and not later than 5 days after the day of filing.

…

22(1) If a market participant fails to pay an ISO fee, the Independent System Operator may refer the matter to the Commission.

…

25(1) A market participant may make a written complaint to the Commission

(a) about an ISO fee, or

(b) about an ISO rule that is in effect, on one or more of the following grounds:

(i) that the ISO rule is technically deficient;

(ii) that the ISO rule does not support the fair, efficient and openly competitive operation of the market;

(iii) that the ISO rule is not in the public interest.

(1.1) The Market Surveillance Administrator may make a written complaint to the Commission about an ISO rule that is in effect on one or more of the following grounds:

(a) that the ISO rule may have an adverse effect on the structure and performance of the market;

(b) a ground set out in subsection (1)(b)(ii) or (iii).

(2) A complaint about an ISO fee must be made within 60 days after the day on which the market participant receives notice of the fee.

(3) Repealed 2011 c11 s3.

(4) The Commission may decline to hold a hearing or other proceeding if, in the opinion of the Commission,

(a) the complaint is frivolous, vexatious, trivial or otherwise does not warrant a hearing or other proceeding, or

(b) the complaint or the substance of it has been referred to, should be referred to, or is the subject of investigation by, the Market Surveillance Administrator.

(4.1) Where a market participant files a complaint, the market participant has the onus of proving

(a) that the ISO rule is technically deficient,

(b) that the ISO rule does not support the fair, efficient and openly competitive operation of the market, or

(c) that the ISO rule is not in the public interest.

(4.11) Where the Market Surveillance Administrator files a complaint, the Market Surveillance Administrator has the onus of proving

(a) that the ISO rule may have an adverse effect on the structure and performance of the market,

(b) that the ISO rule does not support the fair, efficient and openly competitive operation of the market, or

(c) that the ISO rule is not in the public interest.

(4.2) The Commission must decline to hold a hearing or other proceeding if, in the opinion of the Commission, the complaint or the substance of it relates to the Independent System Operator's compliance with the Commission rules made under section 20.9 in making the ISO rule.

(5) Unless the Commission otherwise orders, a complaint under this section does not relieve the person making the complaint from the obligation

(a) to pay an ISO fee pending a decision of the Commission, or

(b) to comply with an ISO order or ISO rule pending a decision of the Commission.

(6) The Commission may, after hearing a complaint, by order,

(a) determine the justness and reasonableness of the ISO fee and confirm, change or revoke the fee,

(b) direct the Independent System Operator to reimburse a market participant any fee paid to the Independent System Operator,

(c) confirm the ISO rule,

(d) disallow the ISO rule, or

(e) direct the Independent System Operator to change the ISO rule or a provision of the ISO rule.

(7) The Independent System Operator must file with the Commission an ISO rule that is changed pursuant to an order under subsection (6)(e).

(8) The Commission must publish notice of the filing of an ISO rule under subsection (7) as soon as possible and not later than 5 days after the day of filing.

(9) A change to an ISO rule filed under subsection (7) comes into effect on the latest of

…

30(1) The Independent System Operator must submit to the Commission, for approval under Part 9, a single tariff setting out

(a) the rates to be charged by the Independent System Operator for each class of system access service, and

(b) the terms and conditions that apply to each class of system access service provided by the Independent System Operator to persons connected to the transmission system.

(2) The rates to be charged by the Independent System Operator for each class of service must reflect the prudent costs that are reasonably attributable to each class of system access service provided by the Independent System Operator, and the rates must

(a) be sufficient to recover

(i) the amounts to be paid under the approved tariff of the owner of each transmission facility,

(ii) the amounts to be paid to the owner of a generating unit in circumstances in which the Independent System Operator directs that a generating unit must continue to operate, and the costs to make prudent arrangements to manage the financial risk associated with those amounts,

(iii) farm transmission costs, and

(iv) any other prudent costs and expenses the Commission considers appropriate,

(b) either be sufficient to recover the annualized amount paid to the Balancing Pool under section 82(7), or if the Independent System Operator receives an annualized amount under section 82(7), reflect that amount, and

(c) include any other costs, expenses and revenue determined in accordance with the regulations made by the Minister under section 99.

(3) The rates set out in the tariff

(a) shall not be different for owners of electric distribution systems, customers who are industrial systems or a person who has made an arrangement under section 101(2) as a result of the location of those systems or persons on the transmission system, and

(b) are not unjust or unreasonable simply because they comply with clause (a).

(4) The Independent System Operator may recover the costs of transmission line losses and the costs of arranging provision of ancillary services acquired from market participants by

(a) including either or both of those costs in the tariff, in addition to the amounts and costs described in subsection (2), in which case the Commission must include in the tariff the additional costs it considers to be prudent, or

(b) establishing and charging ISO fees for either or both of those costs.

…

124(1) In respect of each tariff application, the Commission may,
subject to section 135,

(a) approve a tariff or any part of it with or without changes, or

(b) refuse to approve a tariff or any part of it.

(2) An approval may be for an interim period specified by the Commission.

***Interpretation Act*, RSA 2000 c I-8**

…

Repeal
35(1) When an enactment is repealed in whole or in part, the repeal does not

…

(c) affect any right, privilege, obligation or liability acquired, accrued, accruing or incurred under the enactment so repealed,

…

Repeal and replacement
36(1) If an enactment is repealed and a new enactment is substituted for it,

…

(b) every proceeding commenced under the repealed enactment shall be continued under and in conformity with the new enactment so far as may be consistent with the new enactment;

…

Appendix 5: Milner complaint 2005

ALBERTA ENERGY AND UTILITIES BOARD

IN THE MATTER OF the Electric Utilities Act, SA 2003, c. E-5.1; the Alberta Energy and Utilities Board Act, RSA 2000, c. A-19.5; the Alberta Energy and Utilities Board Act, RSA 2000, c. A-19.5; the Transmission Regulation, AR 174/2004; and the Alberta Energy and Utilities Board Rules of Practice, AR 101/2001;

AND IN THE MATTER OF the Alberta Electric System Operator Loss Factor Rule 9.2 and the loss factor methodology reflected in Appendix 7 to the Rule and certain conduct of the Alberta Electric System Operator in implementing the Rule;

AND IN THE MATTER OF a complaint application made by Milner Power Inc. before the Alberta Energy and Utilities Board pursuant to sections 25 and 26 of the Electric Utilities Act, SA 2003, c. E-5.1.

MILNER POWER INC. COMPLAINT APPLICATION
ELECTRIC UTILITIES ACT SECTIONS 25 AND 26

NATURE OF THE COMPLAINT

TAKE NOTICE that Milner Power Inc.[1] (the "Applicant") brings the present complaint before the Alberta Energy and Utilities Board ("Board") pursuant to sections 25 and 26 of the *Electric Utilities Act*, SA 2003, c. E-5.1 (the "*EUA*") and sections 19 and 22 of the *Alberta Energy and Utilities Board Rules of Practice*, AR 101/2001 ("*Rules of Practice*") concerning Alberta Electric System Operator ("AESO") Loss Factor Rule 9.2 and the loss factor methodology reflected in Appendix 7 to Rule 9.2[2] (the "Rule"), and concerning certain conduct of the AESO in failing to comply with Board directives and in implementing the Rule.

RELIEF SOUGHT

AND TAKE NOTICE that the Applicant seeks orders of the Board:

(a) Directing that the present complaint be set down for hearing in accordance with subsection 25(6) of the *EUA* and section 22 of the *Rules of Practice*;

(b) Directing the AESO to comply with all outstanding Board directives concerning the implementation of the AESO's loss factor methodology in accordance with subsection

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[1] Milner Power Inc. is a wholly owned subsidiary of Maxim Power Corp. Milner Power Inc. owns and operates the H. R. Milner power station (the "Milner Plant") a 144-MW coal-fired power station located near the town of Grande Cache, Alberta.

[2] AESO letter dated May 25, 2005 confirms that the "implementation" date of Rule 9.2 and Appendix 7 was May 25, 2005. Rule 9.2 and Appendix 7 are available on the AESO's website at the following links: http://www.aeso.ca/files/July272005_FinalRules.pdf and http://www.aeso.ca/downloads/TLF_FinalRule_May05_App7.pdf.

8(1)(d) of the *Transmission Regulation*, AR 174/2004 (the "*Regulation*") and Board Decisions 2000-1, 2000-27, 2002-064 and 2002-104;

(c) Revoking or suspending the Rule in accordance with subsection 25(6)(b) of the *EUA* until the AESO complies with the Board's outstanding directives and until the Rule is replaced by a loss factor methodology which complies with the *Regulation*;

(d) Directing that the AESO replace its marginal loss factor methodology as set out in the Rule with an "average MW in" methodology or other loss factor methodology as approved by the Board in accordance with subsection 25(6)(b) of the *EUA*;

(e) Directing in accordance with subsection 25(6)(b) of the *EUA* that any loss factor methodology approved by the Board be phased in, so as to limit the variation in loss factors that any generator sees year to year to no more than one half of the average system losses as a percentage of total MW supplied;

(f) Directing that the AESO remove transmission must run ("TMR") MW dispatches from the AESO's Generic Stacking Order ("GSO") for the purposes of establishing loss factors, in compliance with subsection 1(1)(a) of the *Regulation* and pursuant to subsection 25(6)(b) of the *EUA*;

(g) Extending the AESO's present tariff based loss factor methodology from December 31, 2005, on a final basis, as necessary, in accordance with subsection 10(2) of the *Alberta Energy and Utilities Board Act*, RSA 2000, c. A-19.5 (the "*AEUBA*") and subsection 124(1)(a) of the *EUA*, until replaced as requested herein or as otherwise replaced or amended as directed by the Board;

(h) Where it appears to the Board to be just and proper, granting partial, further or other relief in addition to, or in substitution for that applied for, as fully and in all respects as if the present application had been for that partial, further or other relief, in accordance with subsection 10(3)(f) of the *AEUBA*.

GROUNDS OF THE COMPLAINT

AND TAKE NOTICE that the grounds of the present complaint are that the Rule and the AESO's conduct in implementing the Rule are inconsistent with or in contravention of the *Regulation* and/or the Transmission Development Policy[3] (the "Policy") and are otherwise unjust, unreasonable, unduly preferential, and arbitrarily or unjustly discriminatory, in that the Rule:

- Was established and is intended to be implemented by the AESO without the AESO first complying with the Board's outstanding directives;

[3] November 2003 Transmission Development Policy Paper by the Alberta Department of Energy entitled "Transmission Development – The Right Path for Alberta – A Policy Paper" The Policy is available at the following link: http://www.energy.gov.ab.ca/docs/electricity/pdfs/transmissionPolicy.pdf

- Fails to "reasonably recover the cost of transmission line losses on the interconnected electric system by establishing and maintaining loss factors for each generating unit based on their location and their contribution, if at all, to transmission line losses," contrary to subsection 19(1)(a) of the *Regulation*;

- Fails to ensure that "the loss factor in each location must be representative of the impact on average system losses by each respective generating unit or group of generating units relative to load," contrary to subsection 19(2)(d) of the *Regulation*;

- Contravenes the principle of stability in locational signals essential to the underlying purposes of the *Regulation* and the Policy; and

- Determines loss factors for each location on the transmission system under abnormal operating conditions by including the dispatch from TMR generators, contrary to subsection 19(2)(c) of the *Regulation*, and contrary to the underlying purposes of the *Regulation* and the Policy.

STATEMENT OF RELEVANT FACTS

1. During the first five years following the enactment of the *EUA,* up to December 31, 2000, line losses were the responsibility of load customers. The exception to this was that new independent power producers ("IPPs") placed in service during this period paid incremental line loss charges or received incremental credits.[4]

2. On January 1, 2001, Board Decision 2000-1 became operative regarding losses.[5] The Board determined in Decision 2000-1 that effective January 1, 2001, virtually all losses would be payable by generators on an energy basis.[6] The Board also directed that the loss factors be fixed for five years, to December 31, 2005, subject to annual adjustments to reconcile with the total annual cost of losses.[7] The Board agreed in Decision 2000-1 that a marginal loss factor calculation[8] in conjunction with a "swing-bus"[9] approach should be used to calculate losses and found that a "subtraction" or "shift"[10] method to

[4] Decision 2000-1 page 190. Decision 2000-27 page 56.
[5] Decision 2000-1 page 198.
[6] Ibid. page 199.
[7] Decision 2000-27 page 2.
[8] Decision 2000-1 page 199.
[9] In using a swing bus approach the loss factor for a specific generator is evaluated by increasing or decreasing the MW output of the generator in question by a small amount. The required balance between generation plus imports, and load plus transmission losses and exports, is maintained by reducing or increasing the output of a second generator designated as a swing bus by an appropriate amount. The increase or decrease in the MW output from a specific generator is not exactly offset by a decrease or increase in the MW generation at the swing bus because the change in power flows on the transmission system results in a change in the MW losses on the transmission system. The loss factor for each generator is evaluated by dividing the MW change in losses on the transmission system by the MW change in the generators output. Using the swing bus methodology, the loss factor of the generator designated to be the swing bus is zero.
[10] Because transmission losses do not increase or decrease in direct proportion to generator output, multiplying the forecast energy production of each generator by a single generator loss factor and summing the result for all generators, imports, exports and opportunity service loads in Alberta will not equate to the forecast volume

normalizing losses would provide stronger economic signals for generator location and dispatch.[11]

3. The Board directed ESBI Alberta Ltd. ("EAL"), the former Transmission Administrator ("TA"), in Decision 2000-1, to perform a cost/benefit study of real-time losses at a future GTA.[12] The Board further directed EAL to refile certain portions of its 1999/2000 GTA. Part D of EAL's refiling dealt with outstanding concerns and issues related to EAL's calculation of line loss factors.[13]

4. On March 30, 2000, EAL made public the loss factors determined for 2001, which would be fixed for the noted[14] five-year period ending 2005. In response, ATCO Power wrote to EAL and the Board on April 12, 2000 expressing concerns with the methodology selected by EAL in calculating losses. Specifically, ATCO Power was concerned that EAL had selected a "last MW in" marginal approach for existing (i.e. non-IBOC) IPPs and a "first MW in" approach for IBOC generators. ATCO Power expressed the concern, in part, that EAL's proposed methodology discriminated against existing IPPs.[15]

5. On April 18, 2000, the Board issued a letter confirming that the methodology used by EAL in its refilings conformed to the direction contained in Decision 2001-1. However, the Board did note that, as the approved line loss methodology was different from the methodology previously used by EAL, parties should review the posted loss factors and advise the Board and EAL of any inaccuracies in the loss factors no later than April 25, 2000.[16]

6. By letter of April 25, 2000, ATCO Power applied to the Board for a review and variance of the Board's letter of April 18, 2000. ATCO Power requested that the Board direct EAL to revise its approach for calculating marginal loss factors so that existing IPPs would not be disadvantaged. ATCO Power submitted as grounds for the requested review, among other things, that the methodology advanced by EAL was unjust, unreasonable, and discriminatory against existing IPPs.[17]

7. On April 28, 2000, the Board issued a letter wherein the Board indicated its view, in part, that additional Board direction appeared to be necessary to clarify how the Board expected the calculation of individual loss factors to be determined. The Board also directed EAL on April 28, 2000, "to calculate marginal losses for all generators, new and

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of transmission losses. To ensure that the revenue recovered from generators for transmission losses match the forecast cost of transmission losses the Board directed that a constant factor, termed a shift factor, be subtracted from all generator loss factors.

[11] Decision 2000-1 page 199.

[12] Ibid. Directive 40 at page 279. Directive 40 reads: "The Board directs EAL to perform a cost/benefit study of real-time losses, at a future GTA, providing the costs of implementation versus the size of all identifiable benefits."

[13] Decision 2000-27 page 2.

[14] See paragraph 2 above.

[15] Decision 2000-27 page 2.

[16] Ibid.

[17] Ibid. pages 2 to 3.

existing, on the basis of each generator's 'last MW of production,' thereby, creating a level playing field for all generation."[18]

8. On May 5, 2000, the Board received correspondence from EAL questioning the consistency of the Board's April 28 letter of clarification with the Board's directions in Decision 2000-1 to use a marginal methodology to calculate line losses.[19]

9. As a result of the above disputations and recognizing the importance of the line loss issue, the Board established a written hearing process to deal with parties' concerns. The Board indicated it would endeavor to render its decision by May 16, 2000 recognizing the then imminent IBOC and PPA processes.[20]

10. During the course of the written hearing process ATCO Power expressed concern, in part, that EAL's approach to calculating losses would cause existing generators to be charged for losses on the basis of their last MW of production while generators that were assumed to arrive later would be charged on the basis of their first MW of production.[21] ATCO Power noted, "given that the first MW of production at a location will always attract higher credits or lower charges than the last MW, new IPPs will enjoy an advantage not afforded existing IPPs for the duration of the fixed loss factor period."[22]

11. ATCO Power proposed that the Board consider calculating marginal loss factors for all generators on the basis of an "average MW in" approach instead of using a first or last MW in approach. It was suggested that using an "average MW in" or a "mean-MW marginal loss factor" for all generators would achieve fairness as between generators and would provide effective signals for both economic dispatch and the siting of new generation.[23] In an effort to ensure existing IPPs were afforded treatment consistent with the way new generation would be treated under EAL's proposal, ATCO Power also suggested that any methodology should be applied retroactively to all IPPs constructed since 1996.[24]

12. EAL opposed ATCO Power's proposals. EAL denied that ATCO Power's suggested "average MW in" approach was a marginal approach[25] and argued that any variation to EAL's loss factor proposal would place both the IBOC and PPA processes in jeopardy.[26]

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[18] Ibid. page 3.
[19] Ibid.
[20] Ibid. page 4.
[21] ATCO Power also noted that because loss factors can change over time due to system changes, including subsequent generation additions, IPPs face risks that loss credits could diminish as a consequence of their competitors' subsequent actions. The five year fixed period would afford insulation from this but as EAL's proposal discriminated unfairly in favour of new IPPs, the five year fixed period would only serve to lock-in this discrimination.
[22] Decision 2000-27 page 3.
[23] Ibid. page 20.
[24] Ibid. pages 15 to 16.
[25] Ibid. page 55.
[26] Ibid. pages 5, 6, 7, 10, 11 and passim. It is clear that interveners shared this concern (see for example Decision 2000-27 page 28). It is also clear that the Board took note of this concern (see for example Decision 2000-27 page 3 and 56).

13. The Board issued Decision 2000-27 on May 16, 2000. The Board rejected ATCO Power's suggestion that any approved locational loss factors be applied retroactively to the beginning of 1996 for all existing IPPs. The Board stated it "consider[ed] that such an attempt has the potential to undo the justness and reasonableness of the incremental line loss charges or credits received by IPPs placed in service during this period."[27]

14. The Board also rejected EAL's proposal to calculate loss factors on the basis of the "first MW in" for IBOC generators and on the basis of the "last MW in" for existing regulated generators, existing IPPs, and new non-IBOC generators.[28] The Board noted it "consider[ed] it mandatory that all generators be treated the same on a going forward basis."[29] To help ensure this, and to provide the best economic signal for optimal dispatch, the Board directed EAL to use the "last MW in" method for calculating line losses for all generators.[30]

15. In addition, and to more fully ensure that the loss factors charged would reflect the "last MW in" for all generators,[31] the Board directed EAL to prepare a 2002 base case (and 2003-2005 base cases if necessary) to reflect any staging of IBOC generation, and IBOC generation locations, in-service dates and capacities. The Board also concluded that if EAL accepted any IBOC generation with an in-service date earlier than December 15, 2001, EAL should rerun the 2001 base case with the new IBOC generation included.[32]

16. The Board stated the following in Decision 2000-27 respecting the importance of fairness and equity in allocating the costs of losses:[33]

> The Board considers that loss factors should provide a fair and equitable method of allocating the cost of losses incurred by the TA to the TA's supply customers (i.e., the generators connected to the AIES). The Board considers that, ideally, loss factors to generators should be designed to achieve the following two objectives:
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> • Loss signals should provide an appropriate economic signal for optimal system dispatch.
> • Loss signals should provide an appropriate economic signal for the siting of new generation.
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> The Board considers both of these two objectives to be desirable and important in a restructured deregulated environment for generation. However, the Board has some

[27] Ibid. at page 57. The Board further stated at pages 57 to 58, "These charges or credits were calculated based on the loss status of the system at the time the IPP was [placed] in service. The Board does not consider it reasonable or practical to go back in time and try to recreate the loss status of the system at the time of each generation addition. In fact, the Board considers that the complex assumptions that would have to be made could in fact introduce possible inequities to the agreed upon system of charges and credits that were in place during this period."
[28] Ibid. page 58.
[29] Ibid. page 57. Thus upholding the Board's April 28, 2000 direction.
[30] The Board directed that loss factors calculated using the marginal loss factor approach applied to the "last MW in" from a generator. This was implemented by EAL by calculating the marginal loss factor for each generator assuming the generator was dispatched at its STS contract capacity.
[31] Decision 2000-27 page 64.
[32] Ibid. pages 63 to 64.
[33] Ibid. page 53.

reservations that one loss factor, no matter how well designed, would be able to optimally achieve both objectives.

17. Although not accepting ATCO Power's "average MW in" approach in Decision 2000-27, the Board noted that ATCO Power's proposal could have merit[34] and directed EAL to undertake studies and testing of ATCO Power's proposal.[35] The Board specifically directed EAL to study the following losses issues:[36]

- Whether it would be appropriate or necessary to develop a methodology for providing loss signals (that recognize the reduction or increase in system losses caused by adding a new generator at a specific location) for the siting of new generation.
- Whether the Alberta system warrants the use of an "average MW in" approach for the purposes of calculating loss factors for economic dispatch.
- Whether the "average MW in" approach provides optimal economic signals for both economic dispatch and siting of new generation.
- Whether EAL should introduce optional five-year financial losses hedges in addition to or in substitution for the five-year locked in physical hedges.

18. The Board directed EAL to submit the results and recommendations arising from the above losses studies at a future GTA and in any event no later than at the time of submission of EAL's real time losses study.[37]

19. In July 2002 the Board approved a negotiated settlement of EAL's Phase I and Phase II 2002 tariff applications for the period January 1, 2002, through December 31, 2002 (the "2002 Negotiated Settlement"). The 2002 Negotiated Settlement specified in part:[38]

(j) <u>Board Directives</u>: The Settlement does not affect the TA's obligations to comply with Board directives. The TA will, in a timely fashion and in any event not later than December 31, 2002, comply with all Board Directives. None of the Stakeholders, by signing this Settlement or otherwise, agree that the TA has complied with the Board Directives. The TA shall provide quarterly reports to the Stakeholders on the progress to date, and intended completion dates, for all outstanding Board Directives. For clarity, the COS Credit Rate Schedule shall be interim refundable as of January 1, 2002 pending a COT Credit application and approval by the Board. …

(l) <u>Audit and Adjustment of Loss Factor Methodology</u>: The existing loss factor methodology will continue to apply in 2002.

(m) <u>Review of Loss Factor Methodology</u>: The TA will conduct a fundamental review of the treatment of loss factor cost allocation and recovery methodologies.

20. In October 2002 the Board received a letter from EAL requesting further advice and direction from the Board concerning the application of the "last MW in" approach approved by the Board in Decision 2000-27 where changes had been experienced in generator output. In consequence, in Decision 2002-104, the Board approved six loss

[34] Ibid. page 55.
[35] Ibid.
[36] Ibid. pages 64 to 65.
[37] Ibid.
[38] Decision 2002-064 page 23.

factor application rules to assist the TA and stakeholders in determining when and how to change fixed loss factors and when and how fixed loss factors should be changed as a result of changes to generator output. The Board directed the TA to implement the six loss factor application rules effective January 1, 2003.[39]

21. The Board also directed the TA in Decision 2002-104 to report on the status of the review of the loss factor methodology being carried out pursuant to the 2002 Negotiated Settlement at the time of its 2003 GTA; to propose a firm timetable for an application by the TA dealing with the possible implementation of real time losses before the expiry of fixed loss factors on December 31, 2005; to investigate the appropriateness and feasibility of introducing line loss factors that vary with the level of generator output; and to recommend any changes to the existing loss factor methodology and/or the six Board approved loss factor application rules in its 2004 GTA.[40]

22. The Board further noted that its directions from Decision 2000-27[41] to the TA remained outstanding and indicated its agreement with stakeholders that "a comprehensive examination of loss factor methodology should occur during the 2004 GTA with trial implementation of real time loss tariffs effective in 2005. This timing would allow deliberations on this important issue to take place a full year before the expiry of the fixed loss factors on December 31, 2005."[42]

23. Neither EAL nor the AESO has complied with the above directives and settlement undertakings.

24. The AESO filed its 2005 Phase II GTA on October 3, 2004.[43] On January 31, 2005, the AESO filed its 2006 GTA and requested that its 2006 Phase II application replace its 2005 Phase II application filed on October 3, 2004, in its entirety.

25. In Section 9 of its 2006 GTA, the AESO recited a number of the Board's loss factor directives[44] and undertakings given by the AESO (through the former TA) to stakeholders concerning loss factors,[45] and stated:[46]

> **AESO Response** — In light of Sections 19 through 22 of the Transmission Regulation providing for loss factor methodology to be set through the ISO Rule process in place of the AESO Tariff effective January 1, 2006, the AESO respectfully requests relief from the EUB in further line loss investigations related to the quoted Directions from Decisions 2000-1, 2000-27, and 2002-104. The AESO will transmit all related documentation, studies, and stakeholder consultation notes to the ISO Rules development process and continue to seek early resolution of this matter.

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[39] Decision 2002-104 pages 46 to 47.
[40] Ibid. pages 47 to 48.
[41] Quoted above at paragraph 17.
[42] Decision 2002-104 page 15.
[43] The AESO's 2003 GTA was settled by a written process and losses were not addressed (Decisions 2003-077 and 2003-097). The AESO did not file a 2004 GTA.
[44] As specified by the Board in Decisions 2000-1, 2000-27 and 2002-104 and recited above.
[45] See Decision 2002-064 and the discussion of the 2002 Negotiated Settlement above.
[46] AESO 2006 GTA, Section 9 at page 4 of 33. See also Attachment "A" to BR.AESO-047(a) in the AESO 2006 GTA.

26. In November of 2003 the Government of Alberta, through the Alberta Department of Energy (the "Department"), issued the Policy. The Policy states in part:[47]

> The primary purpose of allocating losses to generators is to act as an effective locational incentive. Therefore, the loss factor methodology should be a long term signal and relatively stable, to allow it to be factored into investment decisions. In order of priority, the loss methodology should:
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> a. Provide a locational incentive for generators
> b. Allow the ISO to pursue transmission projects that will reduce overall transmission losses in the long term to the benefit of all consumers, as consumers ultimately pay for losses through their energy price.
> c. Where possible, provide a signal for generation dispatch, so as to minimize transmission losses on real time basis.
>
> Alberta Energy considers that the current loss methodology used by the ISO must be reviewed and made more consistent with average system losses as opposed to marginal locational losses. The intended treatment of losses is further described in the attached Appendix.

27. The Policy also specifies that "Policy implementation must be managed in a manner that is fair and reasonable."[48]

28. The Appendix to the Policy reiterates that the loss charge is intended to provide generators "a long-term siting signal," and "should therefore be stable, predictable and broadly reflective of losses in order to allow it to be factored into investment decisions."[49] The Appendix to the Policy further specifies:[50]

> The loss factor should apply for a reasonable period of time (e.g. 5 years) and the factor should not vary significantly when it is updated. In this respect, adjustments to an area loss factor should not vary by more than about 50% of the system average losses. Given average system losses of about 5%, area loss factors should not change by more than about 2 to 3% when they are updated.

29. The Appendix to the Policy also indicates that the current range of loss factors is "extreme,"[51] with an overall range of 30% across the province. The Appendix stipulates that a "more reasonable range for loss factors would be in the order of 3 times the system average losses. Assuming system average losses of about 5%, the overall range for losses should therefore be about 15% (i.e. +5% to –10%)."[52]

30. The Applicant relied on the assurances of fairness and stability it saw in the Policy in investing in the Milner Plant.[53] The Applicant began negotiations for the purchase of the

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[47] Policy page 6 of 19
[48] Ibid.
[49] Ibid. Section 6.4 of the Appendix to the Policy addresses losses and states, in part, "[t]he foundation principles for recovery of transmission losses are articulated in the body of the policy document."
[50] Ibid.
[51] Ibid.
[52] Ibid.
[53] The Applicant owns and operates the Milner Plant. See footnote 1 above.

Milner Plant in mid 2003 and completed its purchase of the Milner Plant on January 29, 2004. The Applicant understood from the Policy that loss factors were intended to provide a locational signal, and in order to do so must of necessity be stable and predictable. The Applicant further understood from the Policy that the new loss factors would "be established every 5 years and remain fixed for that period."[54]

31. The Applicant knew at the time of its purchase of the Milner Plant, based on the transmission loss factors issued by AESO in October 2003, that the overall (average) loss factor for the Milner Plant would be a *credit* of approximately 7.73% which equated to a loss credit to the Applicant of approximately $3.6 million for 2004. The Applicant understood that the 2005 loss factor number should be similar.

32. Based on the Policy, the Applicant anticipated that the maximum variation in the loss factors applicable to the Milner Plant would be 50% of average system losses, or 2.45%, which would decrease the credit applicable to the Milner Plant to approximately 5%,[55] giving the Milner Plant a yearly credit of approximately $2.6 million for the 5 year period 2006 to 2010.[56]

33. The Department issued the *Regulation* in August of 2004. Part 5 of the *Regulation* provides direction regarding transmission system losses and credits.

34. The AESO has indicated that it began working towards the implementation of new loss factors in mid 2004.[57] On January 13, 2005, the AESO posted two draft reports prepared by Teshmont Consultants LP ("Teshmont"). On February 17, 2005, final versions of these documents were posted on the AESO's website.[58] In the first report Teshmont tested different methodologies to develop individual generator loss factors to allocate losses to generators for specific load flow conditions. Twelve different variations of "direct" and "gradient" approaches to loss factor calculations were evaluated. To the Applicant's knowledge, Teshmont did not at this stage evaluate an "average MW in" approach.[59] The criteria selected by the AESO as appropriate criteria against which to rank the different methodologies considered by it were as follows:[60]

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[54] Policy page 18 of 19.
[55] As shown by way of illustration in the Policy at page 18 of the Policy.
[56] Ibid. page 17 of 19. (The yearly credit realized may vary depending on annual energy production, average pool price and changes to the calibration factor used to balance the recovery of transmission losses with the actual volume of losses incurred.)
[57] The AESO states in its May 25, 2005 stakeholder letter that it "began in May 2004 consulting with stakeholder[s] about the proposed treatment of loss factors for 2006 and beyond to be addressed in new ISO rules." The AESO's May 25, 2005 letter can be found at the following link:
http://www.aeso.ca/files/Issues_Letter_Loss_Factor_Rules.pdf
[58] "Alberta Electric System Operator Loss Factor Methodologies Evaluation Part 1 – Determination of 'Raw' Loss Factors" and "Alberta Electric System Operator Loss Factor Methodologies Evaluation Part 2 – Conversion of Power to Energy Loss Factors" (the "Teshmont Report"). Parts 1 and 2 of the Teshmont Report are available on the AESO's website at the following links:
http://www.aeso.ca/files/LFMethodEvalPart1.pdf
http://www.aeso.ca/files/LFMethodEvalPart2.pdf
[59] The only consideration of an "average MW in" approach by the AESO of which the Applicant is aware was undertaken by the AESO at the request of Applicant and ATCO Power in March 2005. The approach was rejected by the AESO based on flawed criteria. See also the discussion at paragraph 82 below.
[60] The Teshmont Report (Part 1) pages 12 to 17.

1. Shift Factor – methodologies with lower magnitude shift factors were preferred;
2. Number of Generators with raw loss factors that exceed the limits given in the Regulation – methodologies with fewer generators exceeding the "cap" for charges and credits were preferred;
3. Range of Loss Factors – methodologies with a lower range of loss factors applied to generators were preferred;
4. Seasonal volatility – methodologies which had less variation in loss factors over the four seasonal scenarios evaluated were preferred; and
5. Swing Independent – methodologies that did not employ a swing bus were preferred.

35. The AESO selected a preferred methodology from those it tested based on the ranking of the methodologies against the above five criteria. Tested against the above criteria, the AESO's proposed "50% Area Load Corrected Matrix Methodology" ranked highest.

36. The AESO's proposed methodology is a variant of the "Area Load Corrected Matrix Methodology" also evaluated by Teshmont. The AESO's proposed methodology simply takes the results of the "Area Load Corrected Matrix Methodology" and divides those results by two, or, in other words, "scales" the results. No other methodology tested by the AESO was scaled and thus normalized[61] in this fashion.

37. The AESO distributed a draft of its proposed ISO rule changes including its proposed loss factor rule on March 24, 2004. The AESO distributed its final proposed loss factor rule to stakeholders by letter dated May 5, 2005, and advised stakeholders it was proposing that the loss factor rules be approved by the AESO's Executive Rules Committee ("ERC") on May 16, 2005. The AESO also advised stakeholders in its May 5, 2005 letter that the "proposed implementation date" for its loss factor rule was May 25, 2005. The AESO subsequently advised stakeholders by letter dated May 18, 2005, that the Rule had been approved by the ERC and would be "effective" May 25, 2005. The AESO's letter to stakeholders of May 25, 2005 confirmed the May 25, 2005 effective date of the Rule.[62]

[61] There are two means of "normalizing" losses. One is to "scale" the raw loss factor such as the AESO has done here, where the loss factor is divided by a common number. The other is a "shifting" mechanism where a common amount is added to or subtracted from the raw loss factor. The Board stated the following in Decision 2000-1 (at pages 199 to 200):

> The Board notes that EAL considers the subtraction or shift method proposed by the Coalition to be a reasonable approach to normalizing losses. The Board further notes that the Coalition proposal also has the support of both generators and load customers. As considerable stakeholder concern was expressed on the issue of losses, this consensus is valuable support for the shift method of calculating losses. Furthermore, the Board considers that this method provides stronger economic signals for generator location and dispatch. The Board notes EAL's position that it would find the Coalition proposal acceptable if losses were allocated 100 per cent to generators. For these reasons, the Board approves the subtraction or shift method of calculating time-averaged normalized losses as set out in Section 7.2.3 of the Coalition evidence.

[62] See footnote 57 above.

38. The Rule recites certain loss factor principles and states that the AESO's loss factor methodology "must have regard" to these principles. The Rule states (in part):[63]

> a. **Loss factors** must be determined for each location on the transmission system as if no abnormal operating conditions exist;
> b. The **loss factor methodology** should be a long-term signal and relatively stable, to allow it to be factored into investment decisions.
> c. The **loss factor** in each location must be representative of the impact on average **transmission system losses** by each respective **generating unit** or group of **generating units** relative to load.

The AESO did not rank the loss factor methodologies it studied against these principles.

39. The Rule does not provide for a phase-in of the AESO's proposed loss factor methodology and does not limit or cap changes to loss factors following the effective date of the Rule.

40. On March 8, 2005, the Applicant submitted a proposal to the AESO to phase-in changes to loss factors for those generators adversely impacted by the proposed changes in 2006.[64] The proposal was intended to address the Applicant's and other stakeholders' concerns related to stability and fairness in the implementation of the proposed methodology. The Applicant's proposal envisioned a transitional process where increases in loss factors arising by reason of the adoption of the new methodology would be phased in evenly over a four year period.

41. The AESO responded that it would approach the Department and "[i]f the DOE allows a phased-in approach to those units greatly affected in 2006, the stakeholder group will be canvassed to determine a suitable transition process."[65] The Applicant understands from discussions with the AESO that the Department confirmed a transition from the AESO's present tariff-based methodology to the proposed rule-based methodology would be

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[63] Rule page 2 (bolding in original). Similar principles can be found articulated in the AESO document titled Transmission Loss Factor Methodology Discussion Paper dated February 9, 2005. This paper states (at pages 4 to 5):

a) In order of priority, the loss methodology should:
   - Provide a locational incentive for generators,
   - Allow the ISO to pursue transmission projects where possible, to reduce overall transmission losses in the long term to the benefit of all consumers. …

c) The loss factor methodology should be a long-term signal and relatively stable, to allow it to be factored into investment decisions. …

j) Loss factor in each location must be representative of the impact on average system losses by each representative generator and must be one number at each location that does not vary.

Again, the AESO did not rank the loss factor methodologies it studied against these principles.

[64] The Applicant raised the issues of phase-in and removing TMR from the GSO with the AESO on March 7, 2005. Proposals were advanced by the Applicant on March 8, 2005 at a general stakeholder meeting on loss factors. On March 13, 2005 the Applicant sent documentation to the AESO and other stakeholders requesting a phase-in and the removal of TMR from the GSO. On March 23, 2005 the Applicant submitted further specific proposals to all stakeholders for phase-in and for the removal of TMR from the GSO for the purposes of calculating loss factors.

[65] AESO response to questions posed by the Applicant titled "Questions posed to the AESO by Milner Power Inc. Responses by AESO, 2005-03-15."

permissible. The AESO subsequently proposed a phase-in, but declined to include such a proposal in its Rule once it appeared stakeholder consensus could not be reached on a phase-in proposal.[66]

42. The AESO has confirmed that it intends to include TMR dispatch in its load flow cases when determining loss factors.[67]

43. On March 8, 2005, the Applicant also submitted a proposal to the AESO that TMR dispatch be excluded from load flow cases used to determine loss factors. The Applicant noted, among other things, that forced-on TMR generation mutes the imbalance between generation and load in an area and that this artificially reduces loss credits and increases loss charges in areas where additional generation is needed.

44. The AESO responded that the AESO was drafting a letter to the Department to clarify the TMR issue.[68] The Applicant understands from communications with the AESO that the Department confirmed TMR could be excluded from the GSO for the purposes of calculating loss factors. Nonetheless, the AESO subsequently responded on April 5, 2005 rejecting the Applicant's proposal to exclude TMR dispatch from load flow cases indicating, in part, that subsection 19(2)(c) of the *Regulation* states "the system is required to be operated in a normal state. Therefore, TMR will be included in the bases cases (for the Rainbow Area), and at the minimum amount specified by the applicable OPP to ensure normal operation."[69]

45. On March 22, 2005, ATCO Power submitted two proposals to the AESO. ATCO Power proposed, among other things,[70] a rule change to accommodate choice of an Incremental

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[66] In the AESO's letter of May 25, 2005 to stakeholders (see footnote 57) the AESO stated:

> **Issue:**
> Three stakeholders requested a phase in period to the new Loss Factor Rules as they will be paying more than with the existing loss factor process.
> **Discussion:**
> The AESO met with stakeholders to consider if there was a basis for an acceptable and reasonable phase in period. What is clear is that this is not the case. As with many new rules, market participants will be negatively or positively impacted, while some may be neutral. The majority of stakeholders did not support a phase in proposal. The ERC noted that there is limited support and significant stakeholder objection to the consideration of the use of a transition period.

In its May 24 stakeholder letter, the AESO states "Those who opposed the transition at the meeting outnumbered those who supported it by about a three to one margin." Some of the parties who had given written support for the transition were unable to attend the meeting where the vote was held. The AESO indicated it was unwilling to reschedule the meeting.

[67] See for example the AESO's May 25, 2005 letter to stakeholders where the AESO states, in part, "Section 19(2) (c) of the Transmission Regulation states that '…loss factors must be determined … as if no abnormal operating condition exists…' The term 'abnormal operating conditions' is defined in the Transmission regulation. The AESO considers provision of TMR to be part of 'normal system operation' and therefore will include it in the loss factor calculation."

[68] AESO "Summary of 2006 Loss factor Meeting Notes and Actions (March 8, 2005 and March 17 and 18, 2005)" item 29.

[69] AESO document titled "Resolution of Issues on the 2006 Loss Factor Methodology" dated April 1, 2005 page 1 of 11. See also footnote 67 above.

[70] ATCO Power also proposed an enhancement to the R-Bus approach which would enable the R-Bus approach to be applied to calculation of both marginal and incremental loss factors based on a single solved loadflow case.

Loss Factor ("ILF") or "average MW in" loss factor approach. Specifically, ATCO Power proposed a change to the Rule to accommodate the use of an "average MW in" approach for those generators whose contributions to system losses are not fairly represented by the AESO's "50% Area Load Methodology."

46. On April 5, 2005, the AESO responded that it would not implement ATCO Power's proposed "average MW in" or ILF approach. The AESO stated in part:[71]

> The Incremental Loss Factor Methodology (ILF) ranks in the middle (8th to 10th) of all 18 of the alternatives in terms of magnitude of shift factor required, the number of generators that exceed the loss factor limits, the range of the loss factors, and the seasonal volatility in the loss factors, and ranks 9th overall.

47. When the AESO's proposed "50% Area Load Methodology," is not scaled, the methodology ranks 11th overall against the five criteria selected by the AESO, or, in other words, lower than ATCO Power's "average MW in" proposal.[72]

48. Based on AESO loss factor forecasts dated April 26, 2005, the loss factors applicable to the Milner Plant commencing January 1, 2006, will be a loss factor *charge* of approximately 4.61%. Thus, if the AESO's selected methodology is implemented as presently proposed, the Applicant will experience a variation on January 1, 2006 in the loss factors applicable to the Milner Plant of over 2.5 times system average losses[73] and in the order of 5 times the loss factor variation the Policy indicated as acceptable.[74]

49. If the AESO's methodology is implemented as presently proposed, the Applicant's present annual credit of approximately \$3.6 million will change to a charge of approximately \$2.6 million per year. A number of generators will be negatively impacted by the AESO's proposed methodology. However, estimates of future loss factors provided by the AESO to date show the Milner Plant to be the most negatively impacted of all generators.[75] This swing from a significant losses credit to a significant losses charge will affect the future financial viability of the Milner Plant; one of the key plants reducing losses on the system.

50. The Applicant has continued to discuss the issues raised in this complaint with the AESO. However, it does not appear the AESO intends to change its proposed methodology, to phase-in its methodology, or to exclude TMR from its GSO for the purposes of calculating loss factors, unless directed by the Board to do so. It is the Applicant's view that further negotiations will not useful without the additional direction from the Board requested herein.

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[71] "AESO Resolution of Issues on the 2006 Loss Factor Methodology" dated April 1, 2005.
[72] The AESO's criteria are set out at paragraph 34 above and discussed at paragraphs 62 to 70 below.
[73] As noted at paragraph 31 above, loss factor presently applicable to the Milner Plant is -7.73% (or, in other words, a credit of 7.73%). Average system losses are slightly less than 5%. The variation between the present credit and the proposed charge is 12.33%, or, approximately 2.5 times average system losses.
[74] See paragraph 28 above. The Policy specifies that changes in loss factors should not exceed one half times average system losses. Average system losses are slightly less than 5%. One half times average system losses is 2.45%. A 12.33% variation is about 5 times 2.45%.
[75] For which information is publicly available. (These estimates were provided by the Applicant to stakeholders at a May 2, 2005 Loss Factor meeting of stakeholders.)

SUBMISSIONS IN SUPPORT OF COMPLAINT

1. The Rule contravenes subsection 8(1)(d) of the Regulation and is otherwise unjust and unreasonable, in that the Rule was made and is intended to be implemented without the AESO first complying with the Board's outstanding directives and the AESO's undertakings

51. The Board's directives as provided in Decisions 2000-1, 2000-27 and 2002-104 are mandatory and admittedly[76] remain outstanding. The fact the AESO has now been directed by the *Regulation* to set its loss factor methodology through the ISO rule making process does not lessen the force of the Board's outstanding directives.

52. Moreover, the importance of ensuring the "average MW in" approach is fully reviewed and implemented where appropriate is further supported by the Policy and the *Regulation*. The Policy states that the "current loss methodology used by the ISO must be reviewed."[77] In stipulating the need for review, the Policy indicates that the AESO's loss factor methodology must be "*made more consistent with average system losses as opposed to marginal locational losses*."[78] In discussing this direction the AESO correctly states, "in particular [the Policy] suggested that the new methodology should reflect a methodology that *uses average losses as opposed to marginal losses*."[79] Notwithstanding the AESO's recognition that the Policy suggests that the new methodology should use average losses as opposed to marginal losses, the AESO's proposed methodology remains a marginal approach.

53. A marginal approach does not provide a good indication of the contribution of the total output of the generator to the losses,[80] and does not provide an answer comparable to the "average MW in" approach for generators on an individual or location-specific basis, as required by subsections 19(1)(a) and 19(2)(d) of the *Regulation*.[81]

54. If implemented as presently proposed, the AESO's loss factor methodology will both create significant instability and will fail to allocate costs to generators on the basis of the contribution (cost-causation) of each generating unit to system losses.

55. It is submitted that the current methodology will not be adequately reviewed, nor should the Board approve a new methodology, until the AESO complies with the Board's directives. Subsection 8(1)(d) of the *Regulation* lends further support to the importance of AESO compliance with the Board's directives in mandating that "in making rules under section 20 of the Act, and in exercising its duties under section 17 of the Act, the ISO must… comply with directives of the Board."

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[76] See paragraph 25 above.
[77] Policy page 6 of 19.
[78] Ibid. (italics added).
[79] AESO Draft Issue Paper January 26, 2005 page 1 (italics added).
[80] The AESO's proposed methodology is a variant of a "gradient approach." Teshmont notes that the "gradient method provides a very good estimate of the incremental losses caused by each generator. However, as losses are typically a function of the square of the generation, it does not provide a very good indication of [the] contribution of the total output of the generator to the losses." (See Teshmont Report at page 2.)
[81] See discussion below at paragraphs 60 to 84.

56. It is submitted that the Board's loss factor directives to the AESO, in particular, to study (a) whether the Alberta system warrants the use of an "average MW in" approach for the purposes of calculating loss factors for economic dispatch; and (b) whether the "average MW in" approach provides optimal economic signals for both economic dispatch and siting of new generation, remain relevant, and may be seen as having greater significance than prior to the issuance of the Policy and the *Regulation*.[82]

57. It is also the case that EAL as former TA, and the AESO through EAL, have agreed, as a term of the 2002 Negotiated Settlement, to comply with all outstanding Board directives related to loss factors and otherwise.[83] It is submitted that the Board should not condone the breach of the provisions of the 2002 Negotiated Settlement.

58. The Applicant requests the Board order the AESO to comply with all outstanding Board directives concerning the implementation of the AESO's loss factor methodology as articulated in Decisions 2000-1, 2000-27, and 2002-104, in accordance with subsection 8(1)(d) of the *Regulation*, in particular, as the directives relate to the study and use of an "average MW in" approach. The Applicant also requests the Board order the AESO to comply with the provisions of the 2002 Negotiated Settlement.

59. It is submitted that the Board should not permit the Rule to displace the AESO's existing tariff based loss factor methodology until the AESO has complied with the Board's directives. The Applicant accordingly requests that the Board revoke (or suspend) the Rule and direct that the AESO's existing tariff based loss factor methodology remain effective until the AESO complies with the Board's directives as ordered herein and until the Board and stakeholders have full opportunity to consider and comment on the studies undertaken by the AESO in compliance with the Board's directives.

2. The Rule contravenes subsection 19(1)(a) of the Regulation; is otherwise unjust, unreasonable, unduly preferential, and arbitrarily or unjustly discriminatory; and contravenes the underlying purposes of the Policy and the Regulation

60. The AESO's proposed Rule fails to reasonably recover the cost of transmission line losses by establishing and maintaining loss factors for *each* generating unit based on the generator's location and contribution to transmission line losses and thus contravenes subsection 19(1)(a) of the *Regulation*. This should not be seen as surprising as the AESO ignored the criterion of establishing appropriate location-specific loss signals when selecting its methodology.

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[82] As discussed above at paragraph 26, the Policy recognizes that the primary purpose of allocating losses to generators is to provide an effective locational incentive, and, in order of priority, the loss methodology should:

a. Provide a locational incentive for generators
b. Allow the ISO to pursue transmission projects that will reduce overall transmission losses in the long term to the benefit of all consumers, as consumers ultimately pay for losses through their energy price
c. Where possible, provide a signal for generation dispatch, so as to minimize transmission losses on real-time basis

The intent of the Board's directives remains consistent with these purposes.

[83] See paragraph 19 above for the TA's specific undertakings to stakeholders.

61. The Applicant has above noted the criteria recited by the Board in Decision 2000-27[84] and by the Department in the Policy[85] as applicable to the selection of an appropriate loss factor methodology. The Applicant fully supports these criteria. Unfortunately, the AESO inexplicably ignored these criteria when selecting its methodology.

62. The criteria selected by the AESO as appropriate criteria against which to rank the different methodologies considered by it are as follows:[86]

    1. Shift Factor – methodologies with lower magnitude shift factors were preferred;
    2. Number of Generators with raw loss factors that exceed the limits given in the Regulation – methodologies with fewer generators exceeding the "cap" for charges and credits specified by subsection 19(2)(f) of the Regulation were preferred;
    3. Range of Loss Factors – methodologies with a lower range of loss factors applied to generators were preferred;
    4. Seasonal volatility – methodologies which had less variation in loss factors over the four seasonal scenarios evaluated were preferred; and
    5. Swing Independent – methodologies that did not employ a swing bus were preferred.

    The AESO's proposed "50% Area Load Corrected Matrix Methodology" ranked highest against these criteria and was selected on this basis.

63. It is submitted that the AESO's criteria are flawed. The unsuitability of the AESO's criteria is illustrated by using the criteria to evaluate the option of simply charging all generators the *same* loss factor; in this case, determined by the system annual losses as a percentage of annual energy supplied. If this option is evaluated against the AESO's criteria, the option will score better than any other methodology since this option:

    1. Has a zero shift factor;
    2. Has no generators that are outside the limits;
    3. Has no variation or range in loss factors;
    4. Has no seasonal volatility; and
    5. Is swing independent.

64. Although scoring the highest against the AESO's criteria, this option is clearly unacceptable, as it produces no locational signal whatsoever and would thus entirely fail to meet the objectives of the Policy and the *Regulation* of sending accurate and effective locational signals to generators.

65. The AESO's first criterion of limiting the magnitude of a common shift factor applied to all generators is a meaningless measure. As accepted by the Board, a shift factor is an appropriate method of aligning the loss charges applied to generators with the total cost

[84] Above at paragraph 16.
[85] Above at paragraphs 26 to 29.
[86] Noted above at paragraph 34 and repeated here for convenience.

of losses.[87] Moreover, the *Regulation* provides for the application of a shift factor, called in the *Regulation*, a "calibration factor,"[88] *independent* of the loss factor methodology. The value of any methodology designed to calculate loss factors is based principally on the methodology's ability to establish and maintain loss factors on a *location-specific* basis for each generating unit based on each generator's location and each generator's contribution to transmission line losses.[89] The contribution of all generators, in aggregate, to system losses, the only impact the AESO's selected loss factor methodology addresses, is properly addressed by the calibration factor.[90]

66. Line losses do not vary linearly with generator output. Superposition[91] therefore does not hold. In other words, adding together each generator's impact on system losses cannot result in a sum which equals system average losses.[92] The AESO's "no shift factor" criterion accordingly precludes the *necessary* correction to ensure that loss factors accurately reflect the generator's impact on system losses.[93] The lower or no shift factor criterion is not a measure of accuracy and militates against the express provisions and underlying purposes of the Policy and the *Regulation* of achieving accuracy in the imposition of loss charges and credits.

67. The AESO's second criterion; namely, selection of a methodology on the basis that it minimizes the range of loss factors and the number of generators outside the 15% spread in credits and charges permitted by the *Regulation*, is unnecessary and counterproductive. Of additional concern is the further criterion (criterion three) that the

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[87] As noted above at paragraph 2, the Board agreed in Decision 2000-1 that a 'subtraction' or 'shift' method to normalizing losses would better preserve economic signals for generator location and dispatch.

[88] Regulation subsections 19(1)(e) and 21(1).

[89] The AESO must of course also ensure its selected loss factor methodology "establish[es] a means of determining, for each location on the transmission system, loss factors and associated charges and credits, which are anticipated to result in the reasonable recovery of transmission line losses," (subsection 19(1)(c)) and that the "the loss factor in each location must be representative of the impact on average system losses by each respective generating unit or group of generating units relative to load," (subsection 19(2)(d)). Significantly, however, each of these concerns is a location-specific concern as well.

[90] The calibration factor is to be selected by the AESO under subsections 19(1)(e) and 21(1) of the Regulation.

[91] The Board described the principle of superposition in Decision 2000-1 as follows (page 132):

> If a system shows effects produced by two or more causes acting jointly, it is permissible, if the effect produced on the system is directly proportional to the cause, to consider that each cause acts independently and then to superimpose the effects. The straightforward but frequently more complicated method is to consider that the causes act jointly and to determine their joint effect.
>
> In any linear network containing bilateral linear impedances and energy sources, the current flowing in any element is the vector sum of the currents that are separately caused to flow in that element by each energy source.
>
> The direct proportionality and linearity between voltage and current, as expressed by Ohm's law, is both reason for and proof the superposition theorem. A generator of 1 volt applied to an impedance of 1 ohm produces a current of 1 ampere. Two generators in phase and in series, each of 1 volt and connected to the same 1 ohm impedance, cause a current of 2 amperes to flow. Therefore, each generator is still the cause for a current of one ampere in the circuit. The total current is thus the sum of the currents produced by the individual generators.

The Board also noted (Decision 2000-1 page 133), "the principle of superposition is not permissible when larger amounts of power are injected because the relation between voltage or current and power is not a linear one, but rather is a quadratic relation."

[92] Coupled with the requirement of the Regulation subsection 19(2)(e) "the loss factor must be one number at each location…"

[93] See discussion above at footnote 10.

AESO has chosen to apply to its approach to compression; namely, that the intent of the *Regulation* can only be met by avoiding having generators at the limits of the allowable loss factor range.[94]

68. One of the fundamental purposes of the Policy and the *Regulation* is to ensure effective and accurate locational signals. The 15% spread in credits and charges imposed by the *Regulation* creates some distortion in these signals through "compression." The AESO's objective should be to minimize these distortions within the structure of the *Regulation*. It has not done so.

69. The Applicant notes that constraining seasonal volatility (the AESO's fourth criterion), where the volatility is itself based on fundamentals, leads to further inaccuracy.

70. Not only has the AESO ignored the correct criteria and applied the wrong criteria in selecting its methodology; the AESO has applied the wrong criteria in a *rigged* fashion. As discussed, the AESO's proposed methodology is a variation of the "Area Load Methodology," itself a variant of a gradient methodology. The Area Load Methodology without variation was rejected by the AESO, as was every other methodology except the 50% Area Load Methodology, which is the marginal loss factor produced by the Area Load Methodology divided by 2. Dividing the Area Load Methodology by 2, scales the results of the loss factor calculations. Both scaling and shifting are properly undertaken to normalize losses. They are not undertaken to calculate raw loss factors. Moreover, as noted, the AESO did not apply a similar additional step to any other methodology considered by it.

71. Had the AESO similarly normalized the remaining methodologies considered by it, one or more or all of the remaining methodologies may also have ranked higher on the basis of the AESO's own criteria than the AESO's chosen methodology. In fact, the "average MW in" approach suggested by ATCO Power ranked higher against the AESO's own criteria than the Area Load Methodology; in other words, higher than the AESO's proposed methodology without scaling.[95]

72. As discussed, in indicating the need for review of the current methodology, the Department stated that the methodology must be "made more consistent with average system losses as opposed to marginal locational losses."[96] In discussing this direction the AESO agreed, "the new methodology *should reflect a methodology that uses average losses as opposed to marginal losses*."[97] Nonetheless, similar to the AESO's existing methodology, the AESO's proposed methodology is a "last MW in" or marginal approach.

73. The Applicant has set out in Appendix "A" to this complaint what the Applicant submits is an appropriate "average MW in" approach to loss factor calculations under the

[94] Comments on Incremental Loss Factor Methodology posted by AESO on April 20, 2005.
[95] See discussion at paragraphs 46 and 47 above.
[96] Policy page 6 of 19.
[97] AESO Draft Issue Paper January 26, 2005 page 1 (italics added).

Regulation and has juxtaposed its proposed "average MW in" approach with the AESO's "last MW in" approach.

74. The Applicant has also set out in Appendix "B" to this complaint, a detailed comparison of the results of implementing the Applicant's proposed "average MW in" methodology and the AESO's "50% Area Load Methodology." The results of the two methodologies are very different.

75. The AESO's proposal significantly undervalues the benefits that loss savers produce because it ignores the initial loss savings caused by the first MWs of production. The first MW of production at a location will always attract higher credits or lower charges than the last MW.[98] Where the generator's "last MW in" increases losses, the lower losses (or loss savings) created by the generator's lower production levels are ignored. Even where the generator's dispatch, considered as a whole, may reduce system losses, the AESO's proposed methodology would see the generator receive a *charge* of one half the loss factor of its last MW of production. Similarly, where the generator's "last MW in" continues to reduce system losses, the AESO's approach gives only one half of the credit associated with the last (and least valuable) MW of production. The AESO's approach in fact benefits those generators causing increased system losses by reducing their loss charges, and harms those generators causing loss reduction by reducing their credits.

76. It is submitted that the AESO's proposed loss factor methodology can not be said to "reasonably recover the cost of transmission line losses on the interconnected electric system by establishing and maintaining loss factors for each generating unit based on their location and their contribution, if at all, to transmission line losses" and is thus unjust and unreasonable, and in contravention of subsection 19(1)(a) of the *Regulation* and the underlying purposes of the Policy and the *Regulation*.

77. The Applicant respectfully requests that the Board revoke the AESO's proposed Rule and that the Board direct the AESO to undertake a reassessment of various loss factor methodologies using appropriate criteria. It is submitted that the criteria should be consistent with the Board's past Decisions, the Policy and the *Regulation* and must ensure that the loss factors imposed fairly and reasonably recover losses from each generating unit based on the unit's location and contribution, if any, to losses.

3. The Rule contravenes subsection 19(2)(d) of the Regulation; is otherwise unjust, unreasonable, unduly preferential, and arbitrarily or unjustly discriminatory; and contravenes the underlying purposes of the Policy and the Regulation

78. The Rule also fails to ensure that "the loss factor in each location must be representative of the impact on average system losses by each respective generating unit or group of generating units relative to load," and thus contravenes subsection 19(2)(d) of the *Regulation*. Again, it would have been mere chance had the AESO's methodology actually met the requirements of the subsection, as the requirements of the subsection were ignored.

[98] See ATCO Power submissions, Decision 2000-27 at page 17.

79. It is only when one considers all generators –together or in aggregate– that the AESO's proposed methodology can be said to approximate average system losses. However, as discussed, it does so only after the application of scaling.[99] Moreover, and importantly, while arguably "recover[ing] the cost of transmission line losses on the interconnected electric system"[100] the AESO's proposed methodology does not provide for a loss factor "*in each location*" which is "*representative of the impact* on average system losses by *each* respective generating unit or group of generating units relative to load."[101] The AESO's proposed methodology does no more than what an adequate calibration factor[102] is to do, and fails to do what a fair and reasonable loss factor methodology is meant to do; namely, provide accurate *location-specific* signals to generators.

80. Contrary to the clear direction in the Policy and the *Regulation*, the AESO's proposed methodology continues to calculate losses on a marginal (or "last MW in") basis. The AESO's proposed methodology is accordingly not in compliance with the Policy or the *Regulation*. The Applicant references and incorporates the submissions made in the preceding section, with necessary changes, and refers the Board to Appendices "A" and "B" hereto.

81. The Board did not accept ATCO Power's proposed "average MW in" approach in Decision 2000-27 due to the impending IBOC and PPA processes and as that approach was considered "beyond the purview"[103] of the Decision 2000-27 process. The Board noted, however, that ATCO Power's proposal may have merit and directed that further study of the proposal be undertaken and that the proposal be considered in a future TA GTA.[104] Neither EAL nor the AESO has undertaken studies of an "average MW in" approach for the Board's consideration.

82. The only consideration of an "average MW in" approach by the AESO of which the Applicant is aware was undertaken by the AESO at the request of the Applicant and ATCO Power in March 2005. The "average MW in" approach was rejected by the AESO based on the criteria used by the AESO in evaluating each of the loss factor methodologies earlier considered by the AESO. As discussed above,[105] these criteria are fundamentally flawed. It is not surprising therefore that the "average MW in" approach would not rank high against the criteria. Moreover, the Applicant has not been provided with any information which would permit the Applicant to test the results of the AESO's analysis. Nor has the Board seen this analysis.[106]

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[99] It should be recalled as well that the Board rejected the 'scaling' methodology in Decision 2000-1 and found that a 'subtraction' or 'shift' method to normalizing losses would provide stronger economic signals for generator location and dispatch. Neither the Policy nor the Regulation precludes the use of a "shift factor."
[100] Wording taken from subsection 19(1)(a) of the Regulation.
[101] As required by subsections 19(1)(a) and 19(2)(d) (italics added).
[102] The AESO is to apply an appropriate calibration factor pursuant to subsection 21(1) of the Regulation "to ensure that the actual cost of losses is reasonably recovered through charges and credits under the ISO tariff on an annual basis."
[103] Decision 2000-27 page 68.
[104] Ibid. page 55.
[105] See discussion at paragraphs 62 to 70.
[106] The AESO proposes to provide access to this information in 2006 well after the loss factors are planned to be in effect by the AESO.

83. It is submitted that the AESO's proposed methodology does not provide for loss factors which are representative of the impact on average system losses by each respective generating unit or group of generating units relative to load as required by subsection 19(2)(d) of the *Regulation* and should be revoked by the Board.

84. The Applicant requests the Board revoke the Rule and order that the AESO replace the Rule with the "average MW in" methodology proposed by the Applicant herein,[107] or with another loss factor methodology as approved by the Board in accordance with subsection 25(6)(b) of the *EUA*.

4. The Rule is unjust and unreasonable and contravenes the principle of stability essential to the underlying purposes of the Policy and the Regulation

85. Regardless of the methodology selected, the Applicant submits it is *imperative* that the methodology be phased in to ensure the stability, fairness and effectiveness of the locational signals the Policy and *Regulation* were meant to ensure.

86. The Policy highlights the importance of stability in ensuring the effective locational incentives sought by the Department. The Policy states: "The *primary purpose* of allocating losses to generators *is to act as an effective locational incentive*. Therefore, the loss factor methodology should be a *long-term signal and relatively stable, to allow it to be factored into investment decisions*."[108] Stability is itself an essential feature of the locational incentives the Government of Alberta intended to promote through the Policy and through the *Regulation* in implementing that Policy.[109]

87. The Department's Framework Paper specifies that, "the market framework and *any refinements or transition* needed *between the current and final states,* must be fair, as orderly as possible, and provide certainty *to existing and new* market participants."[110] The principle of stability mandates the need for transitional measures to mitigate the impacts of large unexpected increases in loss factors to both existing generators and new market participants.

88. The Policy specifies, "*Policy implementation* must be managed in a manner that is *fair and reasonable*."[111] The Policy is itself forward looking and should be applied to all periods subsequent to the date of the Policy. A principle, such as the principle of stability, cannot be applied in an intermittent fashion: rigorously applied in one period and neglected in another. Sporadic application of the principle amounts to no application of the principle.

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[107] See Appendix "A" hereto.

[108] Policy page 6 of 19 (italics added).

[109] The Policy notes, "A regulation under the EUA will be prepared to implement the approved transmission policy." The Department states in its paper entitled "Alberta's Electricity Framework Paper," June 6, 2005 ("Framework Paper"), at page 7 of 51, "In 2004, the government articulated a new transmission policy and approved a regulation to implement the policy."

[110] Framework Paper page 8 of 51 (italics added).

[111] Policy page 6 of 19 (italics added).

89. The above passages from the Policy[112] provide clear statements of Government policy: in this case, that loss factors be long-term and relatively stable. These passages clearly indicate that the Alberta Government intended its assurances as to the longevity and stability of loss factors to be acted on by potential investors in Alberta generation, and, as discussed,[113] the Applicant did act upon these assurances.

90. The principle of promoting rate stability (or limiting rate shock)[114] has formed the basis of both the Board's rejection and adoption of numerous proposed changes in rates and rate design.[115] The Board has applied the stability principle in ensuring that the ISO tariff is "just and reasonable" and is "not unduly preferential, arbitrarily or unjustly discriminatory or inconsistent with or in contravention of [the *EUA*] or any other enactment or any law."[116] ISO rules must satisfy the same standards of fairness as ISO tariff provisions. As with tariff provisions, the Board must "order the Independent System Operator to revoke or change a provision of an ISO rule that, in the Board's opinion, is unjust, unreasonable, unduly preferential, arbitrarily or unjustly discriminatory or inconsistent with or in contravention of [the *EUA*] or the regulations."[117]

91. As noted,[118] recent information supplied by the AESO indicates that implementation of the AESO's proposed methodology will result in some generators experiencing large and unexpected increases in loss factors starting in 2006. Based on the most recent information provided by the AESO, the Applicant's present average *credit* of 7.73% will, upon implementation of the AESO's proposed methodology, change to a *charge* of approximately 4.61%. This is a variance of 12.33% or, in other words, a change approximately 2.5 times greater than average system losses and approximately 5 times greater than the maximum percentage change the Policy indicates as appropriate.

92. The Board has noted that when applying the stability principle or when phasing in rate shifts, it is important to consider both the percentage and monetary impacts of the rate shift.[119] The variance of 12.33% in loss factors applicable to the Milner Plant equates to an annual monetary loss to the Applicant of approximately $5 million from credit levels

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[112] Quoted at paragraphs 86 to 88.
[113] See above at paragraphs 30 and 31.
[114] Also called the principle of "gradualism."
[115] See in particular Board Decision 2004-079 at pages 50 to 51 where the Board quotes Bonbright's rate design criteria and specifically notes the importance of two of Bonbright's "non-cost rate design criteria" to the application there under consideration; namely, (i) stability and predictability of rates which has as its main objective the avoidance of rate shock, and (ii) the practical attributes of simplicity, certainty, convenience, understandability and public acceptability. These "non-cost" related criteria, as articulated by the Board in Decision 2004-079, were the Board's restatement of Bonbright's third and ninth rate design criteria; namely, "[s]tability and predictability of the rates themselves, with a minimum of unexpected changes seriously adverse to rate-payers and with a sense of historical continuity. (Compare 'The best tax is an old tax.')" and the "practical attributes of simplicity, certainty, convenience of payment, economy in collection, understandability, public acceptability, and feasibility of application." For additional examples of the Board's application of the principle of stability see Decisions U99034, U99035, 2000-11, 2001-097, 2003-019, 2003-054 and 2005-018.
[116] EUA section 121(2)(a) and (b).
[117] EUA section 25(6)(b).
[118] See paragraphs 48 and 49 above.
[119] Decision 2004-079 page 52.

reasonably anticipated under the Policy[120] and affects the future financial viability of the Milner Plant.

93. Although other generators are significantly impacted by the AESO's proposed loss factor methodology, the Applicant is the most negatively impacted of all generators. The significant variation in loss factors applicable to the Milner Plant is unfair and unreasonable and violates the principle of rate stability. The variation in loss factors applicable to the Milner Plant which will result should the AESO's loss factor methodology be implemented as presently proposed, is especially unfair and unreasonable given the assurances expressed in the Policy and relied upon by the Applicant. Moreover, the magnitude of the variation undermines the stability essential to the locational signals the loss factors are intended to convey.

94. The Board has noted that different rate design criteria may conflict.[121] The Board has pursued cost-causation as a primary rate design criterion, but has balanced or tempered this criterion with the stability principle where rate shock would otherwise occur.[122] Importantly, as proposed by the AESO, the AESO's loss factor methodology satisfies neither the principle of cost-causation nor the principle of stability.

95. In applying the stability principle, the Board must determine an appropriate limit or cap to the rate, or, in the present case, to the loss factor adjustment. The Policy provides guidance in this respect. The Policy stipulates that loss factors should remain stable for a five-year period and that, when permitted, adjustments to loss factors should not vary by more than about 50% of the system average losses, or, in other words, 2 to 3%.

96. The *Regulation* permits the AESO to set loss factors for a period as short as one year and no more than five years.[123] The AESO has determined to limit the application of loss factors to one year, thereby prejudicing the Applicant and other generation owners who relied on the stability which would be provided by the five-year period application period discussed in the Policy. Given the AESO's determination, the Applicant requests the Board direct, pursuant to subsection 25(6)(b) of the *EUA*, that any loss factor rule adopted by the AESO expressly provide for a transition period or phase-in, so as to limit or cap any change from present loss factors levels such that, on a going forward basis, no generator sees a year to year difference in its loss factors of more than one half average system losses as a percentage of total MW supplied. The Applicant has provided proposed wording of a phase-in provision in Appendix "A" hereto.

97. It is of some significance that while the Board must ensure that the methodology is, as applied, both just and reasonable and in accordance with the Policy and *Regulation*, the AESO ignored all such considerations.[124] The Applicant and other stakeholders proposed a phase-in to the AESO. The AESO made a phase-in proposal to stakeholders, but

[120] The loss is in the amount of approximately $6.2 million per year from present credit levels.
[121] Noting Bonbright's own statements to this effect.
[122] Decision 2004-079 page 51.
[123] Subsection 19(2)(a) of the Regulation.
[124] As noted above at paragraph 38, the AESO included reference, among other things, to the principle of stability in the Rule. However, as the AESO did not test its proposed methodology against these principles, the reference in the Rule to the principles amounts to no more than lip service.

subsequently withdrew the proposal. Significantly, rather than assessing whether the Applicant's phase-in request would promote fairness, the AESO asked for a straw vote of stakeholders and simply adopted the outcome of that vote.[125] Where the game is zero-sum, it would be mere chance if deciding on the basis of a show of hands achieved a fair and reasonable solution.

98. The Applicant has made submissions herein that the Rule should be revoked. The Applicant submits that it is essential to the preservation of the principle of stability that the present tariff-based loss factor methodology not be terminated and replaced until a new (replacement) methodology is proposed which complies with the express terms and underlying purposes of the Policy and *Regulation*. No acceptable methodology has yet to be proposed by the AESO. The Applicant accordingly requests that the Board direct, as necessary, that the AESO's present tariff based loss factor methodology be extended from December 31, 2005 on a final basis in accordance with subsection 10(2) of the *AEUBA* and subsection 124(1)(a) of the *EUA*, until replaced as requested herein or as otherwise replaced as directed by the Board.

99. Subsections 30(4)(a) and 30(4)(b) of the *EUA* specify that the ISO "may recover the costs of transmission line losses and the costs of arranging provision of ancillary services acquired from market participants" by "including either or both of those costs in the tariff" or by "establishing and charging ISO fees for either or both of those costs." As section 30 of the *EUA* grants the power to the AESO to recover the costs of losses through the ISO tariff or through ISO fees, nothing in the *Regulation* should be read as undermining or restricting that power. Accordingly, no aspect of the AESO's proposed loss factor methodology is required to be included in the ISO tariff. Accordingly, no aspect of the AESO's proposed loss factor methodology need be approved by September

[125] A vote of stakeholders who were present was taken during the AESO's stakeholder meeting in May 2005. The AESO notes this vote in its correspondence to stakeholders dated May 25, 2005 under the heading "Transition of the Implementation of the New Loss Factor Methodology." The relevant portion of the letter is quoted at 66 above. In addition to the lack of consensus --the operative basis upon which the AESO rejected the Applicant's transition proposal-- the AESO also claimed (in its May 24, 2005 correspondence) that when making the transition from 2000 to 2001 on a new loss factor process, the Board denied a transition or deferral on changes to loss factors. The AESO stated it believes the regulatory conditions are presently similar to what they were in 2001, and would accordingly not expect the Board to support a transition in 2006. The AESO also stated that generators have known loss factors were going to change in 2006; that new generators connecting to the AIES during the transition period may view the transition as a barrier to entry into the market; and that the AESO is "unable and unwilling to conduct detailed financial analysis on the myriad of other market or business forces that will impact generating companies in 2006 and beyond." First, the AESO's task is not to do what is popular. Its task is to do what is fair and reasonable. Second, the Board did not reject a transition proposal in 2000. It rejected a retroactive adjustment to the loss factors received by existing IPPs. It did so because it was concerned the existing IPPs might lose benefits already gained. Moreover, "regulatory conditions" today are not at all like the conditions facing the Board in 2000. At that time the Board was facing the impending IBOC and PPA processes. Certainty was all-important. Third, while generators have known losses were to change in 2006, this does not mean the AESO is now free to institute any change of any magnitude. The transition to the new methodology is to be fair and reasonable and the principle of stability respected. Fourth, the AESO's proposed methodology harms those generators benefiting the system through loss reduction and benefits those generators harming the system through loss amplification. Accordingly, a transition period as proposed by the Applicant could only act as a barrier to entry into the market to those generators who might otherwise have located in an area where siting of new generation would further increase system losses. Fifth, no one is asking the AESO to conduct detailed financial analyses on a myriad of issues. The Applicant is asking that the AESO comply with the Board's outstanding directives.

1, 2005, and no aspect of the AESO's proposed loss factor methodology need be effective by January 1, 2006.

5. The Rule contravenes subsection 19(2)(c) of the Regulation; is otherwise unjust, unreasonable, unduly preferential, and arbitrarily or unjustly discriminatory; and contravenes the underlying purposes of the Policy and the Regulation by including MW dispatch from TMR generators in the AESO's GSO

100. The AESO has indicated that it intends to include TMR dispatch in the GSO for the purposes of calculating loss factors. In the Applicant's submission, this contravenes subsection 19(2)(c) of the *Regulation*, which specifies, "loss factors must be determined for each location on the transmission system as if no abnormal operating conditions exist."

101. Subsection 1(1)(a) of the *Regulation* defines "abnormal operating conditions" as including "conditions where transmission facilities are out of service, emergency conditions exist, construction or commissioning of transmission facilities occur or situations when transmission facility maintenance cannot be coordinated with generation outages." Abnormal operating conditions accordingly include emergency conditions but are not restricted to emergency conditions.

102. As the definition defines "abnormal operating conditions" as *including* certain listed conditions, other conditions of the same kind are also to be included. It is submitted that if "conditions where transmission facilities are out of service" amount to abnormal operating conditions, so too should conditions be considered abnormal where the AESO has failed to bring transmission facilities into service in a timely way. Similarly, if "construction or commissioning of transmission facilities" is an abnormal operating condition, so too should conditions be considered abnormal where the AESO has failed to construct or commission transmission facilities in a timely way.

103. Subsection 8(4) of the *Regulation* addresses the use of TMR in the following manner:

> 8(4) In considering the design and planning of the transmission system, the ISO may consider specific and limited exceptions to the requirements of subsection (1) and propose a non-wires solution
>
> (a) in areas where there is limited potential for growth of load, and the cost of the non-wires solution is materially less than the life-cycle cost of the transmission wires solution, compared over an equivalent study period, or
>
> (b) if the non-wires solution is required to ensure reliable service due to the shorter lead time of the non-wires solution, for a specified limited period of time.

104. Referring to the use of TMR the Department has recently stated:[126]

> **4.4.2. Transmission Must Run (TMR)**
>
> TMR services are acquired by the ISO when it is necessary to dispatch or direct generation to operate out of merit to ensure that the interconnected transmission system

[126] Framework Paper, page 36 of 51 (italics added).

> is operated in a reliable manner. The Transmission Policy and Regulation provide policy direction respecting TMR services.
>
> *TMR services are generally expected to be short-term solutions* and the ISO is directed to develop a robust transmission system which will minimize the need for TMR in the long term. TMR may, however, be *used in emergency or maintenance conditions as a transition mechanism* before new transmission is built, or as a long term alternative to transmission development. This long term alternative would apply when transmission reinforcement is uneconomic, such as in remote areas with limited potential for load growth. Where TMR is used, the cost of TMR (or similar) arrangements will be recovered from load customers in the same manner as wire costs as part of the transmission tariff (i.e. regulated costs).

105. The Department stated in the North/South Application that, transmission congestion is "counterproductive to the interests of customers" and "calls for action."[127] The Department also stated that the AESO is to "plan the transmission system to be congestion free" and to "proactively plan transmission that is: sufficiently robust to allow for transmission of 100% of anticipated in-merit electric energy referred to in section 17(c) of the Act when all transmission facilities are in service."[128] The Department has further stated that TMR "should not be considered as a substitute for transmission or preclude the development of a robust transmission network."[129]

106. The Applicant takes no position as to whether use of TMR for the purposes articulated in subsection 8(4)(a) is or is not indicative of normal operating conditions. Whether use of TMR as a long-term substitute for wires, where there is limited potential for load growth in an area, is indicative of normal operating conditions, is beside the point, as the AESO has recently confirmed that it uses TMR only as a short-term interim measure:[130]

> The AESO's use of TMR agreements is consistent with the Government of Alberta's Transmission Development Policy and Transmission Regulation. Both the policy and the Regulation stipulate that TMR is intended to be used as a short-term, interim measure until new transmission infrastructure can be brought into service.

107. Consistent with this statement, the AESO's 20-year Development Plan[131] clearly indicates the AESO's intention to construct new transmission into the Northwestern area of the Province. The TMR contracted by the AESO in the Northwest of the Province is a transition mechanism. As the Department notes, use of TMR as a transition mechanism is justified on two bases, first, to respond to emergency conditions, and second, to respond to maintenance conditions.[132] In either case, the TMR contracted in the Northwest (as with all present TMR MW dispatch) is out-of-merit dispatch and thus an abnormal operating condition as defined in subsection 1(1)(a) of the *Regulation*.

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[127] Department Evidence page 8, part IV 4.
[128] Department Evidence page 10, part IV 12.
[129] Department letter dated October 25, 2004 entered into evidence in the North/South 500 kV hearing.
[130] AESO stakeholder letter dated November 12, 2004, regarding Rossdale TMR agreement, at page 1.
[131] Document issued by the AESO and titled "20-Year Outlook Document (2005 – 2024)" dated June 2005.
[132] See quote above at paragraph 104.

108. The Applicant submits on the basis of the above that all present TMR MW dispatch must be excluded from the AESO's GSO for the purposes of calculating loss factors if loss factors are to be determined as if no abnormal operating conditions exist.

109. The Applicant further submits that even assuming, without accepting, that inclusion of some or all TMR in the GSO complies with the letter of subsection 19(2)(c) and the Department's policy statements; the inclusion of TMR MW dispatch in the GSO distorts the generation market contrary to the Policy and in a manner that is unjust, unreasonable, unduly preferential, and arbitrarily or unjustly discriminatory.

110. The Policy states:[133]

> In the few cases where transmission constraints are not removed, TMR arrangements should not set or distort market prices. Rather TMR contracts should be provided on a cost of service basis by the owner and should not be a vehicle for exercising market power in a region that is transmission deficient.

111. Including TMR generation in the GSO distorts loss factor calculations. TMR causes generators to run that otherwise would not. The forced-on generation mutes the imbalance between generation and load in generation deficient areas. This artificially reduces loss credits and increases loss charges in areas where additional generation is needed –as evidenced by the need for TMR in the area.

112. This market distortion is especially problematic and unjustly discriminatory, as generators providing TMR can recover the cost of the higher loss factors through their TMR arrangements, while non-TMR generators, in the same area, and which similarly face the higher loss factors caused by the inclusion of the TMR generation in the GSO, cannot do so.[134]

113. The Applicant further submits that, as the inclusion of TMR generation distorts costs and artificially diminishes locational incentives, the inclusion of TMR MW dispatch in the GSO for the purposes of loss factor calculations militates against the underlying purposes of the *Regulation* and all TMR dispatch should accordingly be excluded from the AESO's GSO.[135]

114. The Applicant accordingly requests that the Board direct the AESO to exclude all TMR MW dispatch from the AESO's GSO for the purposes of calculating loss factors.

115. In excluding all TMR MW dispatch, the Applicant proposes that the AESO maintain the MVAR capability of the TMR generators in the load flows used to determine loss

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[133] Policy page 9 of 19.

[134] The Department stated in the North/South Application, "[t]he transmission system should 'not determine winners and losers'" (Department Evidence page 4, part III (a) 8) and that "[c]ongestion on transmission systems creates 'winners and losers'" (Department Evidence page 8, part IV 4). The need for TMR is caused by transmission system congestion. The provision of TMR to remedy congestion need not create winners and losers, but will do so if the AESO is permitted to include TMR generation in the GSO.

[135] The AESO discusses the GSO at subsection 3.2 of Appendix 7 to the Rule. Suggested wording changes to the AESO's GSO have not been provided herein.

factors, and scale the overall system load down to match the TMR MW dispatch removed from the GSO. The Applicant has provided proposed wording for the exclusion of TMR MW dispatch from the GSO in Appendix “A” hereto.

116. The Applicant repeats its requests for the relief sought herein and further requests that the Board grant partial, further or other relief in addition to, or in substitution for that applied for, as fully and in all respects as if the present application had been for that partial, further or other relief, where it appears to the Board to be just and proper, in accordance with subsection 10(3)(f) of the *AEUBA*.

ALL OF WHICH IS RESPECTFULLY SUBMITTED THIS 17th DAY OF AUGUST 2005

HEENAN BLAIKIE LLP

MONTE S. FORSTER
Counsel for the Applicant

Appendix "A"
Milner Power Inc. Complaint dated August 17, 2005
Description of "average MW in" methodology

The Applicant has proposed that the Board approve an "average MW in" approach similar to what the Applicant understands was proposed by ATCO Power in 2000 and which the Board directed the AESO to study and report to the Board and stakeholders on in Decisions 2000-1, 2000-27 and 2002-104 and which the AESO undertook (through the former TA) to study in the 2002 Negotiated Settlement. The AESO describes its proposed "Corrected R Matrix 50% Area Load Adjustment Methodology" in Appendix 7 to the Rule. The Applicant proposes the following wording changes to the Rule to incorporate an "average MW in" approach to the AESO's loss factor calculations. The Applicant has also included herein, suggested wording changes to Appendix 7 to address the Applicant's concerns regarding a phase-in of the AESO's new loss factor methodology and the exclusion of TMR from the GSO. The Applicant has included the present wording of the AESO's proposed "50% Area Load Adjustment Methodology" (sections 2.1 and 2.2 of Appendix 7 to the Rule) below for the Board's assistance.

Description of "average MW in" methodology with changes to incorporate phase-in and exclusion of TMR in GSO: Comparison with AESO Sections 2.1 and 2.2 wording

The Applicant's proposed "Average MW in" Methodology	**The AESO's proposed "50% Area Load Adjustment Methodology"**
2.1 Load Flow Loss Factors ('Adjusted' Raw Loss Factors)	**2.1 Load Flow Loss Factors ('Adjusted' Raw Loss Factors)**
Raw loss factors are calculated for each **generating unit** for each of twelve base case **load** flow conditions. Each base-case **load** flow is selected to represent a forecast of typical operating condition on the **transmission system**, based on historical system loading conditions and a forecast of **generating unit** outputs based on historical generator operation and/or supported forecasts provided by generating unit owners.	**Raw loss factors** are calculated for each **generating unit** for each of twelve base case **load** flow condition. Each base-case **load** flow is selected to represent a typical operating condition on the **transmission system**, based on historical system loading conditions and historical **generating unit** outputs.
The twelve base cases used to determine the **load** flows for the **interconnected electric system** are:	The twelve base cases used to determine the **load** flows for the **interconnected electric system** are:
• used to give weighted average values of transmission system **loading** conditions and losses;	• used to give weighted average values of transmission system **loading** conditions and losses;
• represented over each of four - "three-month seasons" of the year (winter, spring, summer and fall); and	• represented over each of four - "three-month seasons" of the year (winter, spring, summer and fall); and

• the weighted average values are taken at representative peak, median and low **load** conditions for each season.	• the weighted average values are taken at representative peak, median and low **load** conditions for each season.
Each **generating unit** will be modeled in the twelve base cases using the following criteria:	Each **generating unit** will be modeled in the twelve base cases using the following criteria:
	• Adjustments are made to the historical power generation output if necessary to reduce imports and exports set to zero using a **generic stacking order** for generation;
	• Other **generating units** will be added or removed to reduce exports to zero according to the **generic stacking order** but recognizing any constraints imposed by the **transmission system**.
• Adjustments may be made to the forecast generation levels based on historical generation data to correct for major maintenance outages, and major forced outages.	• Adjustments are made to historical data to correct for major maintenance outages, and major forced outages.
• Adjustments are made to the forecast generation levels based on historical power generation to remove the MW amounts of Transmission Must Run (TMR) dispatch. Generators which historically provided TMR will continue to be modelled as on-line with unreduced MVAR capability. The overall system load will be reduced by an amount equal to the MW amounts of TMR dispatch that have been removed.	
• Adjustments are made to the historical power generation output if necessary to reduce imports and exports to zero using a **generic stacking order** for generation;	
In the proposed methodology, the calculation of **raw loss factors** may be done analytically with a custom program that uses the load flow solution as a base and computes the **raw loss factors** analytically for each **generating unit**.	The methodology to determine a load flow based **'raw' loss factor** for one of the **generating units** is called the "Corrected R Matrix 50% Area Load Adjustment Methodology". In the proposed methodology, the calculation of **raw loss factors** will be done analytically with a custom program that uses the load flow solution as a base and computes the **raw loss factors** analytically for each **generating unit** in a single numerical process.

In the methodology, it is assumed:	In the methodology, it is assumed:
• That two load flow scenarios for the **generating unit** for which the loss factor is to be evaluated are prepared. In the first scenario the **generating unit** for which the loss factor is to be evaluated is set to the full MW output that is normal for that season and scenario. Generation is dispatched up or down using the **generic stacking order** to insure interchange with outside jurisdictions is zero. In the second scenario the output of the **generating unit** for which the loss factor is to be evaluated is set to zero MW and the AIES load reduced so that interchange with outside jurisdictions is kept at zero. In both scenarios it is assumed the **generating unit** for which the loss factor is to be evaluated is going to supply the next increment in **load** on the **AIES**;	• That the **generating unit** for which the loss factor is to be evaluated is going to supply the next increment in **load** on the **AIES**;
• For both scenarios the **generating unit** for which the **loss factor** is to be calculated becomes the swing bus for the **transmission system**;	• The **generating unit** for which the **loss factor** is to be calculated becomes the swing bus for the **transmission system**;
• For both scenarios every load within the AIES would be increased by a common factor and a loss gradient would be determined for the **generating unit** equal to the total change in **system losses** divided by the change in output of the **generating unit** for which the **loss factor** is being calculated; and	• Every load within the AIES would be increased by a common factor and a loss gradient would be determined for the **generating unit** equal to the total change in **system losses** divided by the change in output of the **generating unit** for which the **loss factor** is being calculated; and
• The **raw loss factor** for the **generating unit** is set equal to the average of the loss gradients determined for the two scenarios representing the first MW of production and the last MW of production from each generator.	• The **raw loss factor** for the **generating unit** is set equal to ½ of the gradient.
Several assumptions inherent in the analytical method are:	Several assumptions inherent in the analytical method are:
• For each scenario, all bus voltages (and bus voltage angles) remain unchanged.	• All bus voltages (and bus voltage angles) remain unchanged. This is a reasonable assumption if the magnitude of the power change is very small;

• For each scenario, the var component of the **load** is unchanged as a result of the change in MW **load**;	• The var component of the **load** is unchanged as a result of the change in MW **load**;
• For each scenario, the var output of the **generating units** is constant. This is consistent with the **load** var change assumption for small changes in **generating unit** output;	• The var output of the **generating units** is constant. This is consistent with the **load** var change assumption for small changes in **generating unit** output;
• For each scenario, the **load** change is applicable to only **loads** in the **AIES**;	• The **load** change is applicable to only **loads** in the **AIES**;
• For each scenario, for **industrial systems** (ISD) where the ISD is receiving power, the increment in **load** is based on the net load at the metering point; and	• For **industrial system** (ISD) where the ISD is receiving power, the increment in **load** is based on the net load at the metering point; and
• For each scenario, for ISD's where the ISD is supplying power, the ISD is treated as an equivalent **generating unit** with output equal to net to grid at point of metering.	• For ISD's where the ISD is supplying power, the ISD is treated as an equivalent **generating unit** with output equal to net to grid at point of metering.
'Raw loss factors' calculated in this manner for every **generating unit** (or equivalent **generating unit**):	**'Raw loss factors'** calculated in this manner for every **generating unit** (or equivalent **generating unit**):
	• when multiplied by the **generating unit** output in MW and summed for all **generating units** in Alberta will account for almost 100% of the **load** flow losses for the **AIES**;
	• result in a **shift factor**, required to compensate for over or unassigned losses, which is extremely small;
• do not include Small Power Research and Development (SPRD) **generating units**; and	• do not include Small Power Research and Development (SPRD) **generating units**; and
• include an additional **load** flow **shift factor** component compensating for the unassigned component of the SPRD **generating units** with distribution based on their power output in the **load** flow.	• include an additional small **load** flow **shift factor** component compensating for the unassigned component of the SPRD **generating units** with distribution based on their power output in the **load** flow.
2.2 Energy Loss Factors	**2.2 Energy Loss Factors**
The proposed process to calculate energy–based normalized **loss factors** for each of the **generating units** is as follows:	The proposed process to calculate energy–based normalized **loss factors** for each of the **generating units** is as follows:
• a seasonal 'adjusted' **raw loss factor** is calculated for each **generating unit**	• a seasonal 'adjusted' **raw loss factor** is calculated for each **generating unit**

equal to the weighted average of the three ‘adjusted’ **raw loss factors** determined for each of the three system loading conditions for the season;	equal to the weighted average of the three ‘adjusted’ **raw loss factors** determined for each of the three system loading conditions for the season;
• the seasonal ‘adjusted’ **raw loss factor** is multiplied by the forecast **generating unit** volumes for each **generating unit** to establish a preliminary allocation of **losses** for each season;	• the seasonal ‘adjusted’ **raw loss factor** is multiplied by the forecast **generating unit** volumes for each **generating unit** to establish a preliminary allocation of **losses** for each season;
• the total allocation is compared to the estimated energy **losses** for the system and a seasonal **shift factor** is introduced to account for any differences between allocated and estimated energy **losses**; and	• the total allocation is compared to the estimated energy **losses** for the system and a seasonal **shift factor** is introduced to account for any differences between allocated and estimated energy **losses**; and
• the **annual loss factor** is calculated as the weighted average of the four seasonal shifted **loss factors**.	• the **normalized annual loss factor** is calculated as the weighted average of the four seasonal shifted **loss factors**.
• For each **generating unit** the **annual loss factor** is adjusted so that the change in the **loss factor** applied to the **generating unit** is limited to no more than 0.5 times the average system losses expressed as a percentage of total MW supplied.	
• the forecast annual recovery of losses is calculated by multiplying the adjusted **annual loss factors** by the appropriate annual generation, import, export or opportunity loads and summing the result.	
• The forecast annual recovery of losses is compared to the forecast transmission energy losses for the system and an annual shift factor that is applied to all **loss factors** is introduced to account for any differences between the forecast recovery of transmission losses and the forecast volumes of transmission losses. The resulting **loss factors** are called **normalized annual loss factors**.	

Appendix "B"
Milner Power Inc. Complaint dated August 17, 2005
Comparison of the results of the implementation of an "average MW in" methodology and the AESO's marginal loss factor methodology

The AESO's proposed loss factor methodology evaluates the impact on system losses of the last MW of production from a generator and then divides this by two. Using this approach, the sum of all losses recovered from all generators will closely match the forecast volumes of transmission losses in aggregate.

While loss factors based on the marginal loss factor (sometimes "MLF") of the "last MW in" divided by two ("MLF/2") recovers the correct amount of transmission losses on an aggregate or global basis, it fails in many cases to recover the correct amounts on a *location-specific* basis as required by the *Regulation*. The MLF/2 approach does not accurately or fairly reflect the benefits derived from and significantly prejudices those generators whose output creates a net reduction in system losses. As the calculation and apportionment of losses is a zero sum game, those generators most responsible for system losses are benefiting at the expense of those generators most benefiting the system through loss reduction. The following examples illustrate this. The first scenario shows where the MLF/2 approach works reasonably well. The second, third and fourth scenarios highlight the weaknesses and resulting unfairness in the AESO's proposed MLF/2 approach.

Scenario 1

In this scenario a generator is connected to the deep power system, modeled as an infinite bus, through a radial transmission line. This is shown in Figure 1 below. Losses increase with the square of the generation. Transmission losses as a function of generation in this scenario are shown in Figure 2. The MLF is simply the derivative of the losses as a function of the generation which is a straight line. The MLF as a function of generation for this scenario is shown in Figure 3.

In this scenario the average loss factor is equal to the marginal loss factor of the "last MW in" divided by two. In this scenario this is also equal to the average of the MLF of the "first MW in" and the MLF of the "last MW in." This scenario approximates areas where generation greatly exceeds the area load.

In the following examples, the MLF of the "last MW in" is shown by the blue square. The AESO's proposed MLF/2 approach is shown by the yellow square, and the average loss factor, or, the loss factor using an "average MW in" approach, is shown by the red square.

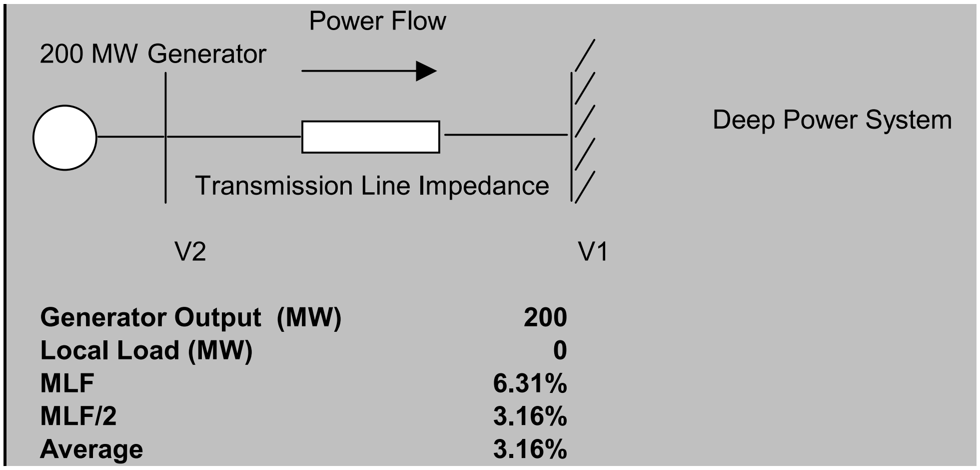


Figure 1: Scenario 1 generator connected to infinite bus through a radial transmission line.

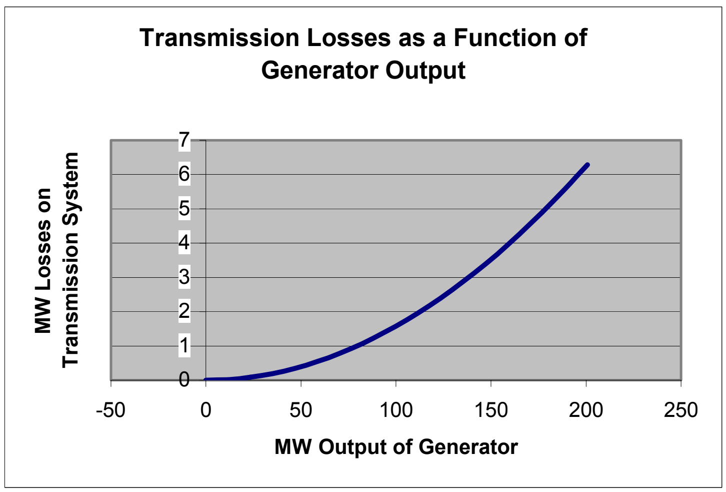


Figure 2: Scenario 1 MW losses on transmission system as a function of generator output.

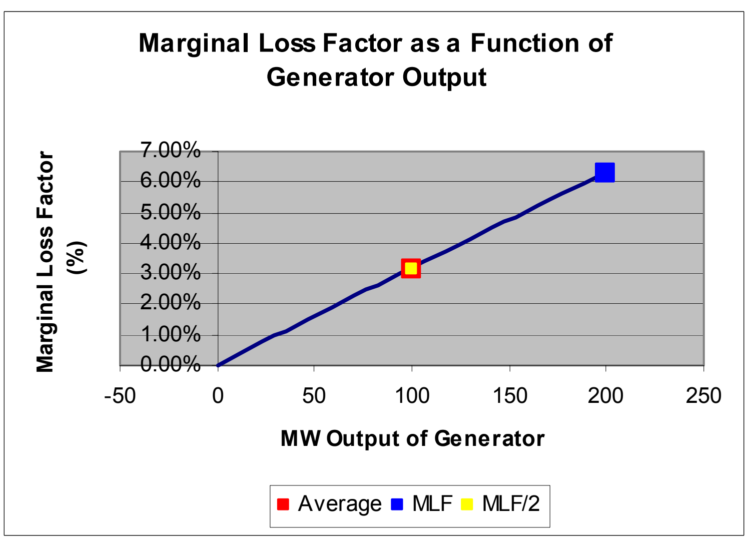
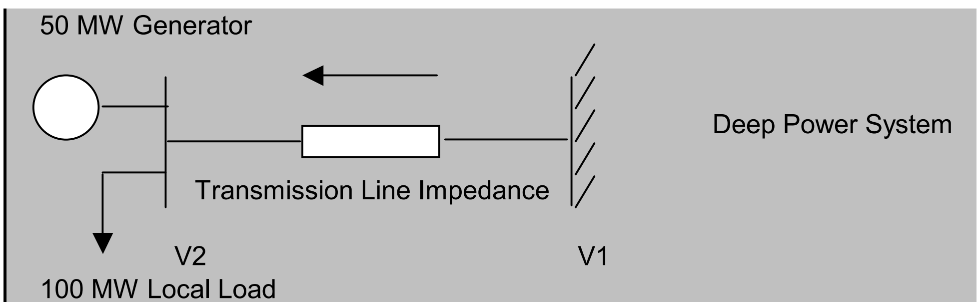


Figure 3: Scenario 1 marginal loss factor as a function of generator output.

Scenario 2

This scenario is similar to Scenario 1 with the exception that there is a local load at the generator bus. The local load is assumed to be relatively small in relation the overall system load. The majority of an increase in generation needed to serve an increase in overall system load will be reflected in a change in flows on the transmission connection to the deep power system. This is shown in Figure 4. In this situation, power flows on the transmission system are dependent on the size of the local load in relation to the generation. If the generator is off line, power flows from the power system over the transmission line to the load. The losses incurred are once again related to the square of the power flow on the transmission line. However, in this case when the generator is added, power flows on the transmission line will be reduced until the generation equals the local load. The transmission losses as a function of generation in this scenario are shown in Figure 5. In areas where generation is less than the local load the marginal loss factor of the last MW in remains a credit, as does the marginal loss factor of the AESO's MLF/2 approach. However, in this scenario, neither marginal loss factor equals the loss factor obtained through an "average MW in" approach. The marginal loss factor as a function of generation for this scenario is shown in Figure 6.



Generator Output (MW)	**50**
Local Load (MW)	**100**
MLF	**-1.65%**
MLF/2	**-0.83%**
Average	**-2.48%**

Figure 4: Scenario 2 generator with local load connected to the deep power system through a radial transmission line.

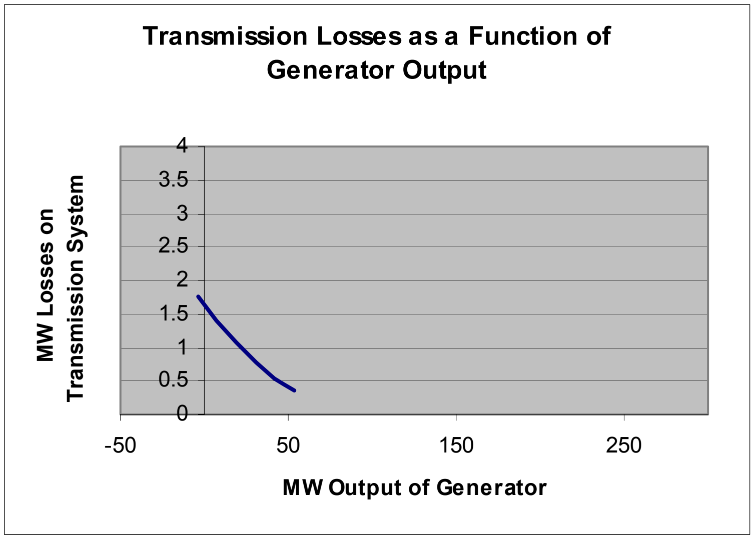


Figure 5: Scenario 2 MW losses on transmission system as a function of generator output.

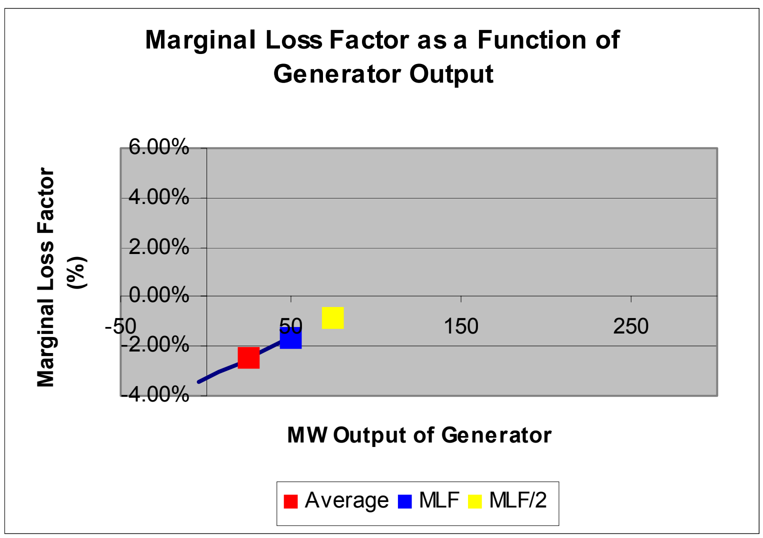


Figure 6: Scenario 2 marginal loss factor as a function of generator output.

Scenario 3

This scenario is similar to Scenario 2. However, in this scenario the generator is approximately twice the size of the local load. Again the local load is assumed to be relatively small in relation the overall system load and an increase in generation to serve an increase in overall system load will be reflected in a change in flows on the transmission connection to the deep power system. This is shown in Figure 7. In this situation the MLF of the first MW in from the generator reduces system losses. The MLF of the last MW in from the generator increases system losses. Since the generator is twice the size of the local load, the amount by which the first MW in reduces system losses is exactly equal to the amount that the last MW in increases system losses. On average this generator has no impact on system losses. The transmission losses as a function of generation in this scenario are shown in Figure 8. Assessing the loss factor based on the average of the MLF of the first MW in and the MLF of the last MW in yields an average loss factor of 0%. However, dividing the marginal loss factor of the last MW in by two yields a loss factor of 1.65%. This loss factor does not reflect the impact on average system losses of the generator. The marginal loss factor as a function of generation for this scenario is shown in Figure 9.

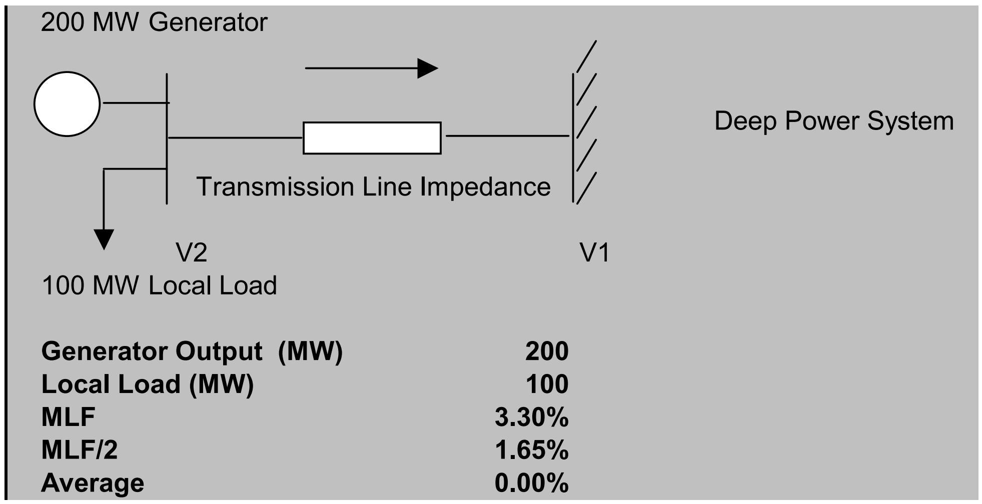


Figure 7: Scenario 3 generator with smaller local load connected to the deep power system through a radial transmission line.

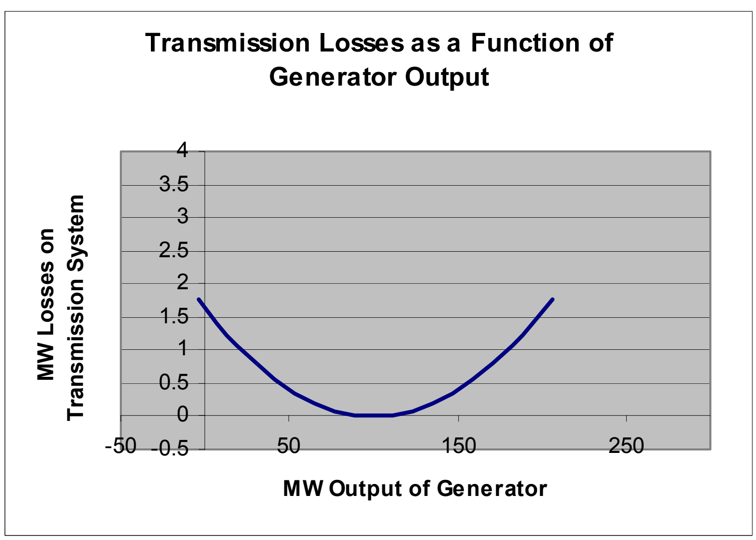


Figure 8: Scenario 3 MW losses on transmission system as a function of generator output.

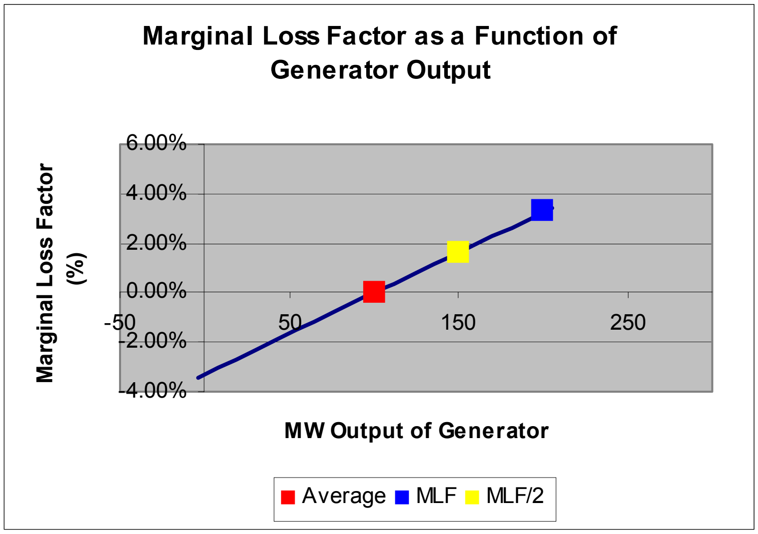
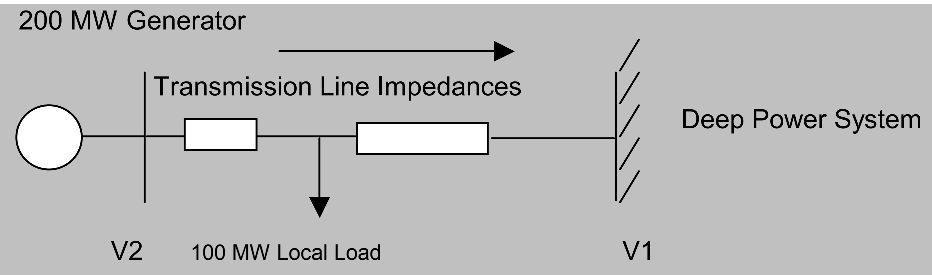


Figure 9: Scenario 3 marginal loss factor as a function of generator output.

Scenario 4

This scenario is similar to Scenario 3. However, in this scenario the local load is somewhat removed from the generator. As before, the local load is assumed to be relatively small in relation the overall system load and an increase in generation to serve an increase in overall system load will be reflected in a change in flows on the transmission connection to the deep power system. This is shown in Figure 10. In this situation the MLF of the first MW in from the generator reduces system losses and the MLF of the last MW in from the generator increases system losses. However, the loss reduction from the first MW of generation is less than the increase in system losses from the last MW of generation. In this case, the average impact is a net increase in system losses. The transmission losses as a function of generation in this scenario are shown in Figure 11. Assessing the loss factor based on the average of the marginal loss factor of the first MW in and the marginal loss factor of the last MW in yields an average loss factor of 0.63 %. Dividing the MLF of the last MW in by two yields a loss factor of 1.85 %. Again, this loss factor does not reflect the impact on average system losses of the generator. The marginal loss factor as a function of generation for this scenario is shown in Figure 12.



Generator Output (MW)	**200**
Local Load (MW)	**100**
MLF	**3.70%**
MLF/2	**1.85%**
Average	**0.63%**
Total Losses (MW)	**2.54**

Figure 10: Scenario 4 generator with smaller local load removed from the generator connected to the deep power system through a radial transmission line.

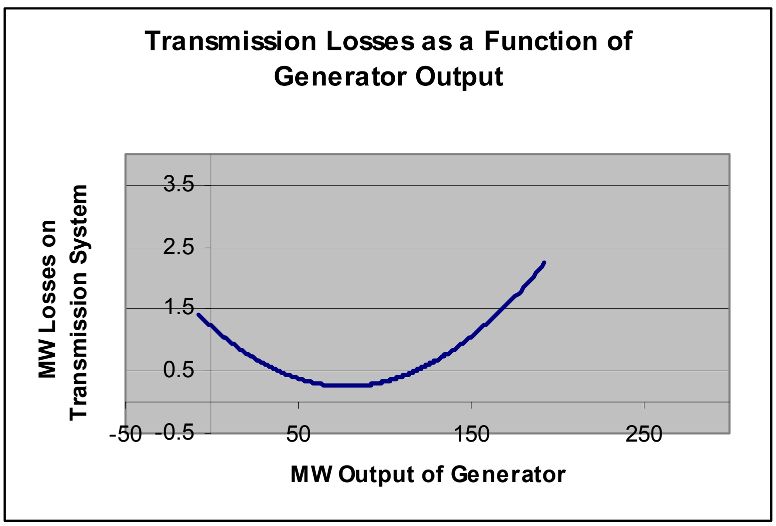


Figure 11: Scenario 4 MW losses on transmission system as a function of generator output.

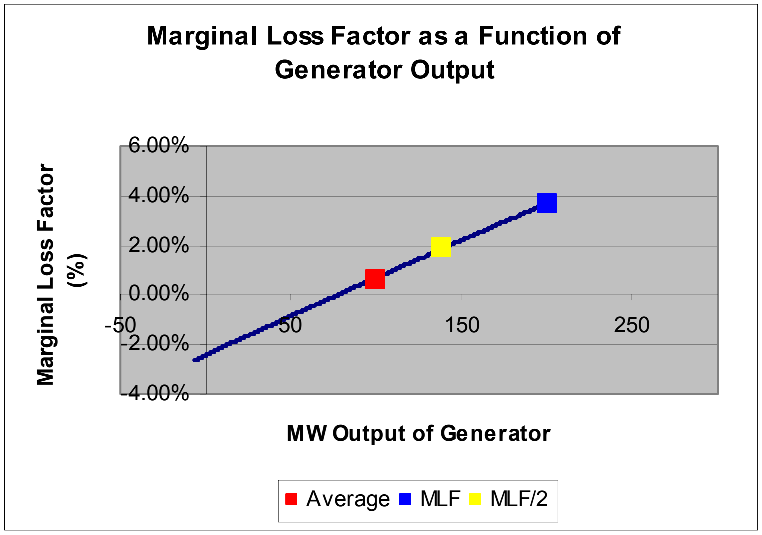


Figure 12: Scenario 4 marginal loss factor as a function of generator output.

In each of the scenarios above, the impact on average system losses of the generator is correctly assessed by averaging the marginal loss factor of the first MW in with the marginal loss factor of the last MW in. In only one of the four scenarios does dividing the marginal loss factor of the last MW in by two, as proposed by the AESO, reflect the impact on average system losses of the generator.

19

Case Name:

Telus Communications Inc. v. Canada (Canadian Radio-Television and Telecommunications Commission)

Between
Telus Communications Inc., appellant, and
The Canadian Radio-Television and Telecommunications Commission, Delta Cable Communications Ltd., on behalf of itself and Coast Cable Communications Ltd., the Canadian Cable Television Association, and Shaw Communications Inc., respondents

[2004] F.C.J. No. 1808

[2004] A.C.F. no 1808

2004 FCA 365

2004 CAF 365

[2005] 2 F.C.R. 388

[2005] 2 R.C.F. 388

246 D.L.R. (4th) 1

327 N.R. 358

135 A.C.W.S. (3d) 64

Docket A-589-03

Federal Court of Appeal
Ottawa, Ontario

Décary, Létourneau and Nadon JJ.A.

Heard: October 12, 2004.
Judgment: October 27, 2004.

(56 paras.)

Telecommunications -- Commissions, regulation -- Variation or recission of decisions -- Powers -- Rates.

Appeal by Telus from Order 2003-54 which it claimed retroactively set rates for its Type B, C and D conduit. In 2000 Telus had requested that the CRTC eliminate the distinction among conduit types such that its entire conduit be brought under the uniform national rate. This request was approved in Order 2000-13 and took effect on February 17, 2000. Order 2000-13, a 256 paragraph decision, dealt with many difficult and controversial issues as well as this more minor request by Telus. In 2003, the CRTC issued Order 2003-54, in which it varied that part of its decision in Order 2000-13 so as to restore the definitions and distinct rates that were in place prior to that decision. In support of its decision to vary its earlier Order, the CRTC stated that there had been no evidence put forward to support the elimination of the distinction. Telus argued that the CRTC had no jurisdiction to vary final rates retroactively or retrospectively under section 62 of the Telecommunications Act.

HELD: Appeal dismissed. The CRTC did not retroactively or retrospectively set rates. Rather, it varied its decision by setting aside part of its decision which was rendered in the absence of any evidence to support it and, therefore, in excess of jurisdiction and in violation of the fundamental duties imposed upon it by the Act. The CRTC's 2003-54 decision was not only legal and reasonable, but it was necessary to insure that the rates for TELUS' Type B to D conduit be just and reasonable. Pursuant to the Act, the CRTC had implied as well as expressed powers to recognize and acknowledge that a previous decision, in whole or in part, was a nullity and it was entitled to proceed to take appropriate corrective measures. It was reasonable to infer that Order 2000-13 intended to deal solely with Type A conduit and establish a uniform rate applicable to this type of conduit alone. Type B to D conduit got caught by Order 2000-13 either by mistake or inadvertence.

Statutes, Regulations and Rules Cited:

Telecommunications Act, S.C. 1993, c. 38, ss. 7(b), 7(c), 7(h) 27, 32(d), 32(e), 32(f), 32(g), 47, 62.

Counsel:

John F. Rook, Q.C., John E. Lowe and Stephen Schmidt, for the appellant.

James Wilson, for the respondent (CRTC).

Lori D. Assheton-Smith and Gerald L. Kerr-Wilson, for the respondent (CCTA).

Christopher C. Johnston, Q.C. and Leslie J. Milton, for the respondents (Delta Cable, Coast Cable, Shaw Communications).

The judgment of the Court was delivered by

1 **LÉTOURNEAU J.A.**:-- Was Telecom Decision CRTC 2003-54 an illegal exercise in retroactive rate-setting as contended by the appellant or was it rather, as the respondents, Delta Cable Communications Ltd. (Delta) and the Canadian Cable Television Association (CCTA) submit, simply a restoration of the status quo ante with respect to rates applicable to Type B, C and D conduit owned by the appellant? A conduit is a type of support structure designed to house and support the wires and other infrastructures used to deliver cable television, high-speed Internet access and other telecommunications services to subscribers. In a nutshell, a conduit is a "reinforced passage or opening in, on, over or through the ground or watercourses capable of containing communications facilities": see paragraph 12 of the

Telecom Decision CRTC 2003-54.

2 The appellant also avers that the decision of the Canadian Radio-television and Telecommunications Commission (CRTC), if found to be legal, is unreasonable in the circumstances. It also complains that it was the victim of procedural unfairness in that it was not given the opportunity to make full and appropriate submissions on the issue of retroactivity. Finally, the appellant submits that the CRTC improperly exercised its discretion in allowing Delta and the CCTA to make an application to challenge its Order 2000-13 almost two years after the Order was rendered.

Facts and procedure

3 The process of determining just and reasonable rates for Type B, C and D conduit owned by the appellant is rich in history and longstanding debates as the facts and these proceedings demonstrate.

4 The appellant, TELUS Communications Inc. (TELUS), is an Incumbent Local Exchange Carrier (ILEC) and is the successor company to BC TEL. The respondents, Delta, Coast Cable Communications Ltd. (Coast) and Shaw Communications Ltd. (Shaw), are cable companies that use conduit provided by TELUS to support their cable infrastructure. The CCTA is a national organization that represents cable companies: as of September 21, 2004, the CCTA has renamed itself the Canadian Cable Telecommunications Association.

5 Between 1978 and 1983, the CRTC approved different rates for four types of conduit provided by BC TEL (Type A to D conduit). Unlike other telephone companies, which offered one type of conduit access, BC TEL offered four kinds, which were distinguishable on the basis of who paid the embedded costs for the supply and installation of the conduit. It is not disputed that the four types of conduit were thus defined:

Type A:	Conduit supplied, installed, owned and maintained entirely by and at the expense of BC TEL.
Type B:	Conduit supplied, owned, and maintained by and at the expense of BC TEL, but installed by BC TEL at the expense of the developer.
Type C:	Conduit owned and maintained by and at the expense of BC TEL, but supplied and installed by BC TEL at the expense of the developer (applied only in the area formerly served by the Okanagan Telephone Company).
Type D:	Conduit owned and maintained by BC TEL, but supplied and installed by and at the expense of the developer.

6 In 1993, the CRTC initiated a review of the use and sharing of costs of telephone company structures. In 1994, it approved interim rates for Type B to D conduit for BC TEL (CRTC 94-996). As a result of the review, in 1995, the CRTC set out basic principles regarding access to support structures and approved a uniform national monthly rate for conduit. It also directed telephone companies to issue tariff pages implementing the decision (CRTC 95-13).

7 Because BC TEL was in the unusual situation of having more than one type of conduit, the CRTC indicated that the uniform rate would only apply to its Type A conduit and directed BC TEL to make specific submissions regarding other conduit types. In the meantime, in CRTC 95-13 it also granted final approval to the monthly rates it had approved for Type B to D on an interim basis in CRTC 94-996.

8 BC TEL's response to the CRTC's request for further submissions was Tariff Notice 3336 (TN 3336), in which it asked that the distinction among conduit types be eliminated and that all of its conduit be brought under the uniform national rate.

9 In CRTC 96-1484, the CRTC deferred disposition of TN 3336, indicating that an investigation of the current demand for and circumstances associated with Type B to D conduit was required prior to making a decision. Indeed, the CCTA objected to BC TEL's statement that costs were no longer a material consideration in setting rates. It submitted that BC TEL should not be allowed to charge the same amount for conduit that it gets free from a developer as it does for conduit that it pays for and installs itself: see page 2 of Order CRTC 96-1484. The CRTC deferred its disposition of BC TEL's Tariff Notice 3336 because it was of the view that the uniform rate proposed by BC TEL might not be appropriate: see Order at page 3.

10 At the same time, the CRTC also established a consultative process led by Stentor Resource Centre Inc. (Stentor) in which telephone companies and cable companies would develop a mutually acceptable model Support Structure Agreement (SSA) and a model support structure tariff.

11 In 1997, Stentor filed a Joint Report as a result of this process, which included a model National Services Tariff (NST) and model SSA. The model NST included the uniform national monthly rate already approved in CRTC 95-13. It also included distinct definitions and different rates for Type B to D conduit for BC TEL. These rates and definitions were, in fact, also those approved by the CRTC in its Decision 95-13: see page 105 of the Appeal Book.

12 In TN 485, Stentor proposed a NST and related SSA that would migrate support structure services from the telephone companies' tariffs to the national services tariff. There was, however, no inclusion of definitions or rates for Type B to D conduit despite their inclusion in the model tariff that had been submitted in the Joint Report.

13 In June 1997, BC TEL submitted for approval Tariff Notice 3637 (TN 3637), in which it asked the CRTC to subsume the deferred decision-making process relating to TN 3336 into its current consideration of Stentor's TN 485. It also asked that the distinction among its types of conduit both in terms of definitions and rates be eliminated and that all of its conduit be brought under the national uniform rate effective the date of approval of TN 485: see Appeal Book, at pages 166-167.

14 In Order 2000-13, the CRTC approved the NST and the SSA proposed by Stentor. It also approved BC TEL's TN 3637, thereby allowing, as we shall see, the withdrawal of distinct rates for Type B to D conduit. These changes took effect on February 17, 2000.

15 Within 15 days of the decision, Shaw contacted the CRTC to express its concerns about the withdrawal of the distinct rates for Type B to D conduit. The CRTC's staff initiated discussions among the parties, seeking a negotiated resolution without the need for more formal CRTC intervention. This process eventually proved unsuccessful.

16 On December 20, 2001, Shaw filed, pursuant to the CRTC Telecommunications Rules of Procedure, a Part VII application requesting that the CRTC initiate a proceeding to consider rates for access to Type B to D conduit, arguing that the issue had been outstanding since Decision 95-13 and that Order 2000-13 was only intended to cover Type A conduit for TELUS (formerly BC TEL). It further asked that the CRTC make the rates approved on a final basis in 1995 for Type B to D conduit interim pending the outcome of such a proceeding.

17 The CRTC received comments on Shaw's application from TELUS as well as from Delta (on behalf of itself and Coast) and the CCTA. In its letter of intervention, although it agreed with Shaw's interpretation of Order 2000-13, the CCTA suggested, in the alternative, that if Order 2000-13 had really eliminated the distinction among conduit types and rates, this was an occasion for the CRTC to exercise its discretion under section 62 of the Telecommunications Act, S.C. 1993, c. 38 (Act) to review that decision. Section 62 gives the CRTC, even on its own motion, the power to review, rescind or vary any decision that it makes.

> 62. The Commission may, on application or on its own motion, review and rescind or vary any decision made by it or re-hear a matter before rendering a decision.

* * *

62. Le Conseil peut, sur demande ou de sa propre initiative, réviser, annuler ou modifier ses décisions, ou entendre à nouveau une demande avant d'en décider.

(emphasis added)

18 TELUS' comments in response to Shaw's application were filed on January 21, 2002. Shaw's reply to TELUS' response came on February 11, 2002. On January 31, 2002, TELUS filed its reply to the CCTA's intervention.

19 On August 13, 2003, the CRTC issued Telecom Decision CRTC 2003-54 (the decision under appeal), in which it varied that part of its decision in Order 2000-13 which had approved TELUS' TN 3637, eliminated the definitions and distinct rates for TELUS' Type A, B, C and D conduit and introduced a uniform definition and a monthly rate of $2.25 per 30 metres for all of TELUS' conduit. That part of the Order was varied "so as to restore the definitions and distinct rates that were in place prior to that decision" (emphasis added): see paragraph 54 of the CRTC 2003-54 decision. The restoration of the prior definitions and rates was made effective 17 February 2000, the date the withdrawal of the rates contained in Decision CRTC 95-13 had originally taken effect.

20 On November 6, 2003, TELUS was granted, by this Court, leave to appeal against Telecom Decision CRTC 2003-54. Before turning my attention to that decision, I will say a word about Order CRTC 2000-13 which eliminated the distinct definitions and rates for TELUS' Type B, C and D conduit.

Rates set for access to telephone companies' support structures, Order CRTC 2000-13, 18 January 2000

21 The CRTC's decision in Order 2000-13 is quite lengthy. It contains 256 paragraphs. Put in general terms, it addresses the issues of national rates, terms and conditions for access to incumbent telephone companies' poles and conduit by cable companies and telecommunications carriers. It also deals with issues of support structure capacity, application of construction standards and the access approval process. Furthermore, it considers the Joint Report filed in 1997 by Stentor.

22 More specifically, the decision rules on the definition of conduit, a person duly authorized to bind a licensee, support structures and spare capacity for future service requirements. It discusses various non-recurring charges resulting from unauthorized attachment, late notification, search, make-ready (costs incurred when work is needed to make spare capacity available) and inspection, monthly rates for recurring charges, the use of a conduit on private property, the obligation to carry insurance to cover legal liabilities, the conditions for terminating an agreement or a permit, the removal of an unauthorized presence on a licensee's facilities, the proposed dispute resolution process, the survival of the SSA terms and conditions beyond termination of the SSA, waiver of SSA conditions, the legal status of agreements prior to SSA, the severability of SSA provisions if some are declared invalid or unenforceable and, finally, the scope of confidentiality provisions with respect to information regarding licensees and companies.

23 I have listed these topics to highlight the wide range of matters confronting the CRTC on that occasion. The questions relating to Type B to D conduit, peculiar as they were and limited in their application to TELUS, appear as a small drop in this sea of difficult and controversial issues. It is against this background that the respondents allege that if Order 2000-13 did eliminate the distinct rates applicable to TELUS' Type B to D conduit, it did so either erroneously or by inadvertence. What was the effect of that Order? Was this effect intended or was it the result of an oversight?

Effect of Order 2000-13 regarding TELUS' Type A, B, C and D conduit

24 The CRTC agreed with the appellant's interpretation of Order 2000-13, namely that the Order had the effect of approving the withdrawal of the distinct rates for Type A, B, C and D conduit and applying a uniform monthly rate of $2.25 per 30 metres for all of TELUS' conduits: see paragraph 38 of the Telecom Decision CRTC 2003-54. I think, however, that it is reasonable to infer that Order 2000-13 intended to deal solely with Type A conduit and establish a uniform rate applicable to this type of conduit alone. I agree with the respondents that Type B to D conduit "got caught" by Order 2000-13 either by mistake or inadvertence. The reasonableness of the inference stems from a number of facts.

25 First, Stentor's Joint Report maintained the distinct definitions and rates for Type A, B, C and D conduit, distinctions which were meant to reflect the embedded costs and the influence they had on the levels of rates.

26 Second, Stentor was aware that TELUS' request for the elimination of the distinct definitions and rates for its Type A, B, C and D conduit had been put on hold, an investigation of the matter had been found appropriate, additional information was needed and the issue was therefore still pending before the CRTC. This is why Stentor's proposal in TN 485 for a uniform rate did not include Type B to D conduit which, of all carriers, TELUS was the only one to possess.

27 Third, all carriers, including TELUS, had Type A conduit. It was, therefore, appropriate for the CRTC to include TELUS in its decision so as to make the uniform national rate accepted for Type A conduit applicable to the Type A conduit owned by TELUS.

28 Fourth, the CRTC had already expressed its views that the uniform rate proposed by TELUS might not be appropriate, given the respondents' strong opposition based on the fact that different costs were incurred by TELUS. One would have expected the CRTC to discuss and rule on the respondents' position if it intended to eliminate the distinct definitions and rates for TELUS' Type A, B, C and D conduit. Nowhere in Order 2000-13 is there any explanation or justification for the substantial change which occurred as a result of the following tersely worded paragraph:

> The Commission approves the following TNs for withdrawal of support structure tariffs effective coincident with the date at which the tariff pages issued pursuant to this order will come into effect:
>
> Bell TN 6022
> BC TEL TN 3637
> NB Tel TN 647
> MTS TN 278

29 This fundamental change was effected by merely inserting BC TEL TN 3637 in the above list found at paragraph 21 of the Order. This is inconsistent with CRTC Decision 95-13 which made final the approval of rates for TELUS' Type B to D conduit and with CRTC Decision 96-1484 which had deferred ruling on TELUS' request to eliminate distinct rates, indicating that further investigation was appropriate prior to making a decision on the request. The only paragraph which might suggest that the CRTC considered the question of Type B to D conduit is paragraph 16 of Order 2000-13 where the CRTC ruled that it was not premature to address the issues raised in the proposed tariffs and SSAs. However, this finding does not deal with the question of the distinct definitions and rates for Type B to D conduit because these types were left out of the tariffs and SSAs proposed by Stentor and by the other companies which did not have these types of conduit. I have no doubt that had the CRTC really intended to make a change of this nature and importance for conduit and telecommunications users, it would have provided some reasons for its decision.

30 In the end, on the basis of the evidence in the record, I believe that it was not the CRTC's intent in its Order 2000-13 to eliminate the distinct definitions and rates for Type B to D conduit owned by the appellant and that this question "fell between the cracks" until the respondents realized the potential effect and impact of the Order and brought it to the attention of the CRTC. Whether the change brought about by Order 2000-13 to Type B to D conduit was the result of an error or an oversight does not really matter as we shall see below. I now turn to a summary of Telecom Decision CRTC 2003-54 and to an analysis of that decision and of the parties' submissions.

Telecom Decision CRTC 2003-54

31 In this decision, the CRTC reviews the history of the approval of different rates for Type A, B, C and D conduit owned by the appellant. It reiterates that, in Decision 95-13, it had noted the different rates for the appellant's various types of conduit and granted final approval for the rates that had been granted interim approval in 1994. It also underlines the fact that, in Order CRTC 96-1484, it put TELUS' request for a uniform rate as proposed in TN 3336 on hold until appropriate investigation could be made of the request in view of the different costs associated with Type B to D conduit: see paragraphs 6, 7 and 8 of the decision. It then proceeded to consider the appellant's objections to the Part VII application by Shaw and to the CCTA's intervention.

a) The time-frame for filing the application

32 Notwithstanding the objection of the appellant, the CRTC was satisfied that there were exceptional circumstances in this case and valid reasons for the delay in filing the Part VII application which justified a derogation from its general policy that an application to vary or rescind, made pursuant to section 62 of the Act, should normally be brought within 6 months of the decision that the party seeks to have reviewed.

33 Within 15 days of the release of Order 2000-13, Shaw had notified the CRTC of its concerns regarding the elimination of the distinction among types of conduit. It had also notified the appellant in May 2000 of these concerns. The CRTC had initiated discussions among the parties (in which it had participated), in an attempt to solve the problem, but these had proven unsuccessful and delayed the filing of the application.

b) The existence of substantial doubt as to the correctness of approving the withdrawal of distinct rates for Type A, B, C and D conduit

34 In the public notice (PN 98-6) that it gave, the CRTC indicated that it would exercise its jurisdiction, pursuant to section 62 of the Act, to review and vary its Order 2000-13 if there was substantial doubt as to the correctness of that Order. After a review of its earlier decisions and proceedings regarding this matter, it concluded that such doubt had been established and that it was appropriate to vary Order 2000-13 as far as Type B to D conduit was concerned.

35 In support of its decision to vary its earlier Order, the CRTC relied on the following facts: it was not satisfied that costs were no longer a material consideration with respect to the appropriate rates for Type B to D conduit, neither Stentor nor TELUS, as specifically requested, had provided any new evidence or argument in favour of the elimination of the distinctions between these types of conduit and there was, with respect to this issue, no evidence on the record of the proceeding leading to Order 2000-13. It also took into account the fact that no prejudice would result to the appellant if Order 2000-13 were varied because the rates authorized by that Order had never been implemented by the appellant. Conversely, Shaw, Delta and Coast would be subject to substantial increases in their operating costs if the uniform rates authorized by Order 2000-13 were implemented. In these circumstances, especially in view of a lack of information and evidence justifying the elimination of the definitions and distinct rates for the appellant's Type B to D conduit, it was never demonstrated that the uniform rate would be "just and reasonable" as required by section 27 of the Act:

> 27. (1) Every rate charged by a Canadian carrier for a telecommunications service shall be just and reasonable.
>
> (2) No Canadian carrier shall, in relation to the provision of a telecommunications service or the charging of a rate for it, unjustly discriminate or give an undue or unreasonable preference toward any person, including itself, or subject any person to an undue or unreasonable disadvantage.
>
> (3) The Commission may determine in any case, as a question of fact, whether a Canadian carrier has complied with section 25, this section or section 29, or with any decision made under section 24, 25, 29, 34 or 40.
>
> * * *
>
> 27. (1) Tous les tarifs doivent être justes et raisonnables.

(2) Il est interdit à l'entreprise canadienne, en ce qui concerne soit la fourniture de services de télécommunication, soit l'imposition ou la perception des tarifs y afférents, d'établir une discrimination injuste, ou d'accorder -- y compris envers elle-même -- une préférence indue ou déraisonnable, ou encore de faire subir un désavantage de même nature.

(3) Le Conseil peut déterminer, comme question de fait, si l'entreprise canadienne s'est ou non conformée aux dispositions du présent article ou des articles 25 ou 29 ou à toute décision prise au titre des articles 24, 25, 29, 34 ou 40.

36 I reproduce key paragraphs of the decision leading to the CRTC's conclusion as well as paragraph 54 which contains that conclusion:

45. In Order 96-1484 the Commission indicated it was not satisfied by BC TEL's argument that costs were no longer a material consideration with respect to the appropriate rates for Type B, C and D conduit, and determined that it would be appropriate to investigate the demand for Type B, C and D conduit and the specific circumstances under which Type was provisioned, before considering the company's request that there be a uniform rate for all of its conduit.

46. The Commission notes that Stentor, in asking the Commission to bring the issue of rates for BC TEL's B, C and D conduit into the scope of the proceeding to consider TN 485, did not provide any new evidence or argument in favour of the elimination of the various types of conduit. Moreover, although the Commission had determined that, in considering the appropriate rates for Type B, C and D conduit, it would be appropriate to investigate the demand and the specific provisioning circumstances for each type, neither Stentor nor BC TEL provided any such information, nor did it form part of the record of the proceeding leading to Order 2000-13. The distinct rates for Type B, C and D conduit were thus withdrawn in the absence of evidence that the demand for these facilities and the circumstances of their provisioning were sufficiently similar to those for Type A conduit to justify a uniform rate.

47. The Commission finds that, in the absence of this information, it has never been demonstrated that a rate of $2.25 for Type B, C and D conduit is just and reasonable as required by section 27 of the Act. The Commission concludes that, in the circumstances, there is substantial doubt as to the correctness of its approval of the withdrawal of the distinct rates for Type B, C and D conduit and the approval of a uniform monthly rate of $2.25 per 30 metres for all types of TCI's conduit.

48. The Commission notes that, based on information provided by parties to this proceeding, the withdrawal of the distinct rates for Type B, C and D conduit would significantly impact the cost of operations of the users of these facilities. Based on the 25 September 2001 TCI invoice filed by Shaw in this proceeding, the Commission estimates that a monthly rate of $2.25 per 30 metres for Type B, C and D conduit would increase Shaw's operating costs by approximately $1 million per year. Such a rate would likely increase the combined operating costs of Delta Cable and Coast Cable by approximately $66,000.00 per year. The Commission considers that the corresponding increase in the revenues TCI received would result from charging a rate that is not just and reasonable. It would appear from the record of this proceeding that TCI has not in fact been collecting the increased amounts.

49. The Commission concludes that, in these circumstances, it is appropriate to vary its original decision insofar as Type B, C and D conduit is concerned.

[...]

53. While the Commission remains of the view, set out in Order 2001-137 that "as a matter of regulatory policy rates approved on a final basis should not generally be subject to adjustment", it also considers that there are circumstances where to fail to make an exception would be to cause

> an injustice to an applicant. The Commission considers that such circumstances are present in this case. While the Commission also remains concerned about the uncertainty that retroactive rate adjustments can cause to carriers, this concern is attenuated in the present case by the fact that it was brought to TCI's attention in May 2000 that the rates for Type B, C and D conduit were at issue.
>
> 54. Accordingly, the Commission varies that part of Order 2000-13 in which it approved the proposal in TN 3637 to eliminate the definitions and distinct rates for TCI's Type A, B, C and D conduit and introduce a uniform definition and monthly rate of $2.25 per 30 metres for all of TCI's conduit, so as to restore the definitions and distinct rates that were in place prior to that decision. The Commission directs TCI to issue forthwith revised tariff pages, reinstating the definitions and the rates for Type A, B, C and D conduit in its serving area in British Columbia given final approval in Decision 95-13, effective 17 February 2000.

(emphasis added)

Analysis of the decision under appeal and of the submissions of the parties

37 I shall address first the appellant's argument that the CRTC had no jurisdiction to vary final rates retroactively or retrospectively under section 62 of the Act.

Whether the CRTC retroactively or retrospectively varied final rates under section 62 of the Act

38 I should state at the outset that the parties agree that the standard of review applicable to the determination of this issue is that of correctness.

39 The appellant contends that, in the context of a positive approval scheme of tariffs and rates, the CRTC has no jurisdiction under section 62 to vary rates which have received final approval, let alone to vary them retroactively, as it did in the present instance, by making its decision effective 17 February 2000. In support of its contention, it cites the decision of the Supreme Court of Canada in Bell Canada v. Canada (CRTC), [1989] 1 S.C.R. 1722. I do not think that this decision carries the particular weight that the appellant attributes to it. The decision stands for the proposition that interim rates can be varied retroactively or retrospectively. For reasons that will become clear, I do not think that this case is of much assistance to the appellant.

40 With respect, I believe the appellant misapprehends and therefore misstates what legally occurred in the case at bar in Decision 2003-54. The CRTC did not retroactively or retrospectively set rates as the appellant contends. Rather, it varied its decision by setting aside that part of its decision which was rendered in the absence of any evidence to support it and, therefore, in excess of jurisdiction and in violation of the fundamental duties imposed upon it by the Act. The effect, as it appears from paragraph 54 of its decision, was simply to restore the status quo ante which the invalid decision had altered. There was no setting of rates in Decision 2003-54.

41 In Judicial Review of Administrative Action in Canada, Toronto, Canvasback Publishing, 1998, at pages 15-14 and 15-15, Brown and Evans describe the acceptance of "absence of evidence" as an independent ground of review of administrative action akin to a jurisdictional error. Under the heading " 'No Evidence' as Jurisdictional Error", they write:

> For nearly 60 years, it was generally accepted that an adjudicative tribunal did not exceed its statutory authority merely by basing its decision on a finding of fact that was unsupported by any evidence, unless the fact in question was "jurisdictional" in nature. Since the late 1970s, however, the courts have quietly abandoned this restrictive approach, and have elevated "no evidence" to

> an independent ground of review with the essential characteristics of jurisdictional error. That is, it can be proved by evidence extraneous to the tribunal's record, and judicial review is not subject to ouster by a preclusive clause.
>
> In the case that marked the most decisive rejection of the earlier law, a decision of a labour arbitrator was held to be invalid on the ground that arbitrators have no jurisdiction to base their awards on findings of fact that are supported by "no evidence". Moreover, the court admitted evidence not in the tribunal's record to establish the error. And subsequently, the Supreme Court of Canada affirmed that decisions may be quashed for "no evidence", despite the presence of a preclusive clause.

42 A decision rendered in the absence of evidence, like a decision rendered without jurisdiction, is a nullity and reviewable as arbitrary. In Douglas Aircraft Co. of Canada v. McConnell, [1980] 1 S.C.R. 245, at page 277, Estey J., dissenting on another point, asserted that arbitrary conduct, absence of evidence and refusal to discharge a function were jurisdictional errors which transcended the classification of errors in law on the face of the record:

> [...] Unfairness, the adoption of procedures contrary to natural justice, arbitrary conduct, refusal to discharge their function, fraud and bias in law, are all matters that transcend the classification of error in law on the face of the record. They are all jurisdictional in the fundamental sense of that term, and hence are reviewable through certiorari or its equivalent, with or without a privative clause. Such errors of law are not the same as but are equatable to the jurisdictional error which may arise from wrongful conclusions in statutory interpretation as in the Jarvis case, supra. Similarly, a decision without any evidence whatever in support is reviewable as being arbitrary; but on the other hand, insufficiency of evidence in the sense of appellate review is not jurisdictional.

(emphasis added)

43 In Chandler v. Alta. Assoc. of Architects, [1989] 2 S.C.R. 848, the Practice Review Board of the Alberta Association of Architects conducted a hearing to review the practices of a firm of architects which had gone bankrupt. However, it issued findings and orders relating to disciplinary matters which were ultra vires the powers of the Board and quashed by the Court of Appeal, [1985] A.J. No. 1022. Being mistaken as to the scope of its powers, the Board failed to consider making recommendations to the Council of the Alberta Association of Architects as it had the duty to do pursuant to paragraph 39(3) of the Architects Act.

44 A month after the decision of the Court of Appeal, the Board gave notice to the parties that it intended to resume the original hearing in order to make recommendations to the Council. An application for prohibition was brought against the Board. The failure of the Board to consider matters which were part of its statutory duty, along with its power to continue the hearing, became the central issues before the courts. Unlike in the case at bar, the Architects Act did not confer on the Board any power to rescind, vary, amend or reconsider a final decision. Yet, at page 862, Sopinka J. found for the majority of the Supreme Court that the Board had the power and the obligation to fulfill its statutory duty:

> Furthermore, it the tribunal has failed to dispose of an issue which is fairly raised by the proceedings and of which the tribunal is empowered by its enabling statute to dispose, it ought to be allowed to complete its statutory task.

> [...]
>
> In this appeal we are concerned with the failure of the Board to dispose of the matter before it in a manner permitted by the Architects Act. The Board intended to make a final disposition but that disposition is a nullity. It amounts to no disposition at all in law. Traditionally, a tribunal, which makes a determination which is a nullity, has been permitted to reconsider the matter afresh and render a valid decision.

(emphasis added)

45 The Supreme Court's approach was followed by the High Court of Australia in Minister for Immigration and Multicultural Affairs v. Bhardwaj, [2002] HCA 11, 187 ALR 117, although some judges expressed different views on whether the impugned decision was of no effect at all or produced some effect until quashed or set aside. At pages 129 and 130, Gaudron and Gummow JJ., with whom McHugh J. agreed, wrote:

> There is, in our view, no reason in principle why the general law should treat administrative decisions involving jurisdictional error as binding or having legal effect unless and until set aside. A decision that involves jurisdictional error is a decision that lacks legal foundation and is properly regarded, in law, as no decision at all.
>
> [...]
>
> In our view, logic and legal principle both direct the conclusion that the approach of the Supreme Court of Canada is correct. As already pointed out, a decision involving jurisdictional error has no legal foundation and is properly to be regarded, in law, as no decision at all. Once that is accepted, it follows that, if the duty of the decision-maker is to make a decision with respect to a person's rights but, because of jurisdictional error, he or she proceeds to make what is, in law, the duty to make a decision remains unperformed. Thus, not only is there no legal impediment under the general law to a decision-maker making such a decision but, as a matter of strict legal principle, he or she is required to do so.

(emphasis added)

46 Both the Chandler and Bhardwaj decisions recognize that many administrative decision-makers possess implied powers of reconsideration to the extent that such powers are "needed 'to enable the tribunal to discharge the function committed to it by [the] enabling legislation' ": see Brown and Evans, supra, at pages 12-107 and 12-108. In the present instance, not only is the power to reconsider implied, it is expressly conferred on the CRTC by section 62 of its enabling legislation.

47 Furthermore, section 27 of the Act, previously cited, requires, as indicated by the use of the word "shall", that rates charged by a Canadian carrier be "just and reasonable". It is the function and duty of the CRTC to ensure that that obligation, imposed upon Canadian carriers, is met at all times. In the Bell Canada case, supra, Gonthier J. wrote for a unanimous Court at page 1740:

> It is obvious from the legislative scheme set out in the Railway Act and the National Transportation Act that the appellant has been given broad powers for the purpose of ensuring that telephone rates and tariffs are, at all times, just and reasonable. The appellant may revise rates at any time, either of its own motion or in the context of an application made by an interested party. The appellant is not even bound by the relief sought by such applications and may make any order related thereto provided that the parties have received adequate notice of the issues to be dealt with at the hearing.

In this regard, section 47, hereafter reproduced, is mandatory. It requires the CRTC to exercise its powers and perform its duties under the Act and any special Act "with a view to... ensuring that Canadian carriers provide telecommunications services and charge rates in accordance with section 27", that is to say services and charge rates that are just and reasonable:

> 47. The Commission shall exercise its powers and perform its duties under this Act and any special Act
>
> (a) with a view to implementing the Canadian telecommunications policy objectives and ensuring that Canadian carriers provide telecommunications services and charge rates in accordance with section 27; and
>
> [...]
>
> * * *
>
> 47. Le Conseil doit, en se conformant aux décrets que lui adresse le gouverneur en conseil au titre de l'article 8 ou aux normes prescrites par arrêté du ministre au titre de l'article 15, exercer les pouvoirs et fonctions que lui confèrent la présente loi et toute loi spéciale de manière à assurer la conformité des services et tarifs des entreprises canadiennes avec les dispositions de l'article 27.

48 There is no doubt that the CRTC has jurisdiction, when so requested by an aggrieved party, to entertain an allegation that, as a result of an earlier decision, services and charge rates have become unjust and unreasonable. There is also no doubt in my respectful view that it has implied as well as express powers to recognize and acknowledge that a previous decision, in whole or in part, is a nullity and proceed to take appropriate corrective measures. Indeed, the legislative scheme governing the CRTC imposes upon it a duty to do so and confers to it broad powers to allow it to fulfill that duty.

49 I have already mentioned the duties imposed on the CRTC by sections 27 and 47 as well as the power accorded to it in section 62 to rescind or vary its decisions. In order to ensure that services and charge rates are just and reasonable, paragraphs 32(d), (e) and (f) give the CRTC a broad discretionary power to suspend or disallow any portion of a tariff that is, in its opinion, inconsistent with section 27. It can, as a corrective measure, substitute or require a Canadian carrier to substitute other provisions for those disallowed, or require such carrier to file another tariff or another portion of it, in substitution for a suspended or disallowed tariff. Paragraph 32(g) gives the CRTC a residual power, in the absence of any applicable provision in Part I, to determine any matter and make any order relating to the rates, tariffs or telecommunications services of Canadian carriers. In this context, it is difficult to envisage a broader power than the one given to ensure that rates are just and reasonable at all times.

50 These duties and powers provided in the Act are consistent with, and designed to implement, the legislative objectives found, for example, in paragraphs 7(b), (c) and (h) of the Act:

7.

[...]

(b) to render reliable and affordable telecommunications services of high quality accessible to Canadians in both urban and rural areas in all regions of Canada;

(c) to enhance the efficiency and competitiveness, at the national and international levels, of Canadian telecommunications;

[...]

(h) to respond to the economic and social requirements of users of telecommunications services; and

[...]

* * *

7.

[...]

b) permettre l'accès aux Canadiens dans toutes les régions -- rurales ou urbaines -- du Canada à des services de télécommunication sûrs, abordables et de qualité;

c) accroître l'efficacité et la compétitivité, sur les plans national et international, des télécommunications canadiennes;

[...]

h) satisfaire les exigences économiques et sociales des usagers des services de télécommunication;

[...]

Rates that are unjust and unreasonable compromise the accessibility of Canadians to affordable telecommunications services and are not responsive to the economic requirements of the users of these services.

51 In conclusion, the CRTC simply acknowledged or recognized the nullity of part of its Order 2000-13 which, in relation to TELUS' Type B to D conduit, "amounted to no disposition at all in law": see Chandler v. Alta. Association of Architects, supra. This acknowledgment had the effect of dissipating doubts as to the applicability of the 1995 final definitions and rates from 1995 to the present because there was no disposition in law modifying them: see paragraph 54 of Telecom Decision CRTC 2003-54. Consistent with that effect, paragraph 55 of that decision directs TELUS to provide the necessary justification for the rate levels that it proposes if it wants to change the rates applicable to Type B to D conduit. In my view, not only was the decision legal and reasonable, it was necessary to insure that the rates for TELUS' Type B to D conduit be just and reasonable.

Whether section 62 of the Act allows the CRTC to vary final rates retroactively or retrospectively

52 In view of my conclusion that the CRTC, in revisiting Order 2000-13, was not engaged in an exercise of retroactive or retrospective rate setting, there is no need to address this issue.

Whether, as contended, the CRTC breached the rules of procedural fairness by not permitting the appellant to make full and appropriate submissions on the issue of retroactivity

53 The record before us shows that the appellant, in its submission to the CRTC in response to Shaw's application, argued the issue of retroactivity and retrospectivity. It cited the Bell Canada decision from the Supreme Court of Canada as well as a number of previous decisions in which the CRTC had concluded that, as a matter of regulatory policy, rates approved on a final basis should not generally be subject to adjustment: see the Appeal Book, at pages 57 and 58, paragraphs 36 to 40 and accompanying footnotes. In its response to the CCTA intervention, the appellant cross-referenced its previous answer to Shaw's application: see the Appeal Book, at page 78, paragraphs 53, 54 and footnote 34.

54 Had I found that the CRTC was engaged in an exercise of retroactive or retrospective rates setting, I would also have found that the appellant had been given ample opportunity to argue the issue of retroactivity and that there was no denial of procedural fairness.

Whether the CRTC improperly exercised its discretion in permitting the respondents to challenge Order 2000-13 outside the 6 month time-limit that it usually applies under section 62 of the Act

55 I see no merit in this ground of appeal. The circumstances were unusual and there was nothing unreasonable in attempting first to resolve the imbroglio through mediation, although it resulted in some delay. In any event, I fail to see how and why, in the best interests of the parties and of the administration of justice, a direct attack could and should be barred by a limitation period when a collateral attack might be permitted against the part of Order 2000-13 that was rendered without jurisdiction: see R. v. Litchfield, [1993] 4 S.C.R. 333 and Dagenais v. Canadian Broadcasting Corp., [1994] 3 S.C.R. 835. In addition, I do not think that Parliament intended that a review of unjust and unreasonable rates, set in violation of the Act, be precluded by a time limit which would instead allow such rates to remain in place and flourish.

56 For these reasons, I would dismiss the appeal with costs.

LÉTOURNEAU J.A.
DÉCARY J.A.:-- I agree.
NADON J.A.:-- I agree.

cp/e/qw/qlaim/qlhcs

20

Ontario Energy Board

Commission de l'énergie de l'Ontario

EB-2013-0128

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, (Schedule B);

AND IN THE MATTER OF an application by Essex Powerlines Corporation for an order approving just and reasonable rates and other charges for electricity distribution to be effective May 1, 2014.

BEFORE: Marika Hare
Presiding Member

Allison Duff
Member

DECISION and RATE ORDER

March 13, 2014

Essex Powerlines Corporation ("Essex") filed an application with the Ontario Energy Board (the "Board") on September 27, 2013 under section 78 of the Act, seeking approval for changes to the rates that Essex charges for electricity distribution, effective May 1, 2014 (the "Application").

The Application met the Board's requirements as detailed in the *Report of the Board: Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach* (the "RRFE Report") dated October 18, 2012 and the *Filing Requirements for Electricity Distribution Rate Applications* (the "Filing Requirements") dated July 17, 2013. Essex selected the Price Cap Incentive Rate-Setting ("Price Cap IR") option to adjust its 2014 rates. The Price Cap IR methodology provides for a mechanistic and formulaic adjustment to distribution rates and charges in the period between cost of service applications. Essex last appeared before the Board with a full cost of service application for the 2010 rate year in the EB-2009-0143 proceeding. In this proceeding, Essex also seeks approval for Lost Revenue Adjustment Mechanism Variance Account ("LRAMVA") balances.

The Board conducted a written hearing and Board staff participated in the proceeding. The Vulnerable Energy Consumers Coalition ("VECC") applied for and was granted intervenor status and cost eligibility with respect to the proposed recovery of revenue losses due to conservation programs. One letter of comment was received. The letter of comment requested non-consolidated financial statements from Essex's holding company and affiliates. The Board provided a response to the letter, indicating that the Board's Yearbook of Electricity Distributors contains financial information on Essex, but that it does not have regulatory jurisdiction over Essex's holding company and affiliates and therefore does not have the information requested.

While the Board has considered the entire record in this proceeding, it has made reference only to such evidence as is necessary to provide context to its findings. The following issues are addressed in this Decision and Rate Order:

- Price Cap Index Adjustment;
- Rural or Remote Electricity Rate Protection Charge;
- Shared Tax Savings Adjustments;
- Retail Transmission Service Rates;
- Review and Disposition of Group 1 Deferral and Variance Account Balances; and
- Review and Disposition of LRAMVA Balance.

Price Cap Index Adjustment

The Board issued the *Report on Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors* (the "Price Cap IR Report") which provides the 2014 rate adjustment parameters for distribution companies selecting either the Price Cap IR or Annual IR Index option.

Distribution rates under the Price Cap IR option are adjusted by an inflation factor, less a productivity factor and a stretch factor. The inflation factor for 2014 rates is 1.7%. Based on the total cost benchmarking model developed by Pacific Economics Group

Research, LLC, the Board determined that the appropriate value for the productivity factor is zero percent. The Board also determined that the stretch factor can range from 0.0% to 0.6% for distributors selecting the Price Cap IR option, assigned based on a distributor's cost evaluation ranking. In the Price Cap IR Report, the Board assigned Essex a stretch factor of 0.15%.

As a result, the net price cap index adjustment for Essex is 1.55% (i.e. 1.7% - (0% + 0.15 %)). The price cap index adjustment applies to distribution rates (fixed and variable charges) uniformly across all customer classes. The price cap index adjustment does not apply to the components of delivery rates set out in the list below.

- Rate Riders;
- Rate Adders;
- Low Voltage Service Charges;
- Retail Transmission Service Rates;
- Wholesale Market Service Rate;
- Rural or Remote Electricity Rate Protection Charge;
- Standard Supply Service – Administrative Charge;
- Transformation and Primary Metering Allowances;
- Loss Factors;
- Specific Service Charges;
- MicroFit Charge; and
- Retail Service Charges.

Rural or Remote Electricity Rate Protection Charge

The Board issued a Decision and Rate Order (EB-2013-0396) establishing the Rural or Remote Electricity Rate Protection ("RRRP") benefit and charge for 2014. The Board determined that the RRRP charge to be paid by all rate-regulated distributors and collected by the Independent Electricity System Operator ("IESO") shall be increased to $0.0013 per kWh effective May 1, 2014, from the current $0.0012 per kWh. The draft Tariff of Rates and Charges flowing from this Decision and Rate Order reflects the new RRRP charge.

Shared Tax Savings Adjustments

In its *Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors,* the Board determined that a 50/50 sharing of the impact of legislated tax changes between shareholders and ratepayers is appropriate.

The tax reduction will be allocated to customer rate classes on the basis of the last Board approved cost of service distribution revenue.

The Application identified a total tax savings of $157,696 resulting in a shared amount of $78,848 to be refunded to rate payers.

The Board approves the disposition of the shared tax savings of $78,848 based on a volumetric rate rider using annualized consumption for all customer classes over a one-year period from May 1, 2014 to April 30, 2015.

Retail Transmission Service Rates

Electricity distributors are charged for transmission costs at the wholesale level and then pass on these charges to their distribution customers through the Retail Transmission Service Rates ("RTSRs"). Variance accounts are used to capture differences in the rate that a distributor pays for wholesale transmission service compared to the retail rate that the distributor is authorized to charge when billing its customers (i.e. variance Accounts 1584 and 1586).

The Board issued revision 3.0 of the *Guideline G-2008-0001 - Electricity Distribution Retail Transmission Service Rates* (the "RTSR Guideline") which outlines the information that the Board requires electricity distributors to file to adjust their RTSRs for 2014. The RTSR Guideline requires electricity distributors to adjust their RTSRs based on a comparison of historical transmission costs adjusted for the new Uniform Transmission Rates ("UTR") levels and the revenues generated under existing RTSRs. Similarly, embedded distributors, such as Essex, must adjust their RTSRs to reflect any changes to the applicable Sub-Transmission RTSRs of their host distributor(s), which in this case is Hydro One Networks Inc.

The Board approved new rates for Hydro One's Sub-Transmission class, including the applicable RTSRs, effective January 1, 2014 (EB-2013-0141), as shown in the following table.

2014 Sub-Transmission RTSRs

Network Service Rate	$3.23 per kW
<u>Connection Service Rates</u> Line Connection Service Rate Transformation Connection Service Rate	 $0.65 per kW $1.62 per kW

The Board finds that these 2014 Sub-Transmission class RTSRs are to be incorporated into the filing module.

Review and Disposition of Group 1 Deferral and Variance Account Balances

The *Report of the Board on Electricity Distributors' Deferral and Variance Account Review Initiative* provides that, during the IRM plan term, the distributor's Group 1 account balances will be reviewed and disposed if the preset disposition threshold of $0.001 per kWh (debit or credit) is exceeded. The onus is on the distributor to justify why any account balance in excess of the threshold should not be disposed.

Essex's 2012 actual year-end total balance for Group 1 accounts including interest projected to April 30, 2014 is a credit of $4,592,942. This amount results in a total credit claim of $0.0080 per kWh, which exceeds the preset disposition threshold. Essex proposed to dispose of this credit amount over a one-year period.

In its submission, Board staff noted that the principal amounts as of December 31, 2012 reconcile with the amounts reported as part of the *Reporting and Record-keeping Requirements*. Board staff submitted that the amounts should be disposed on a final basis.

The Board approves the disposition of a credit balance of $4,592,942 as of December 31, 2012, including interest as of April 30, 2014 for Group 1 accounts. These balances are to be refunded to customers over a one-year period from May 1, 2014 to April 30, 2015.

The table below identifies the principal and interest amounts approved for disposition for Group 1 accounts.

Group 1 Deferral and Variance Account Balances

Account Name	Account Number	Principal Balance A	Interest Balance B	Total Claim C = A + B
LV Variance Account	1550	$708,191	$19,695	$727,886
RSVA - Wholesale Market Service Charge	1580	-$3,573,954	-$147,000	-$3,720,954
RSVA - Retail Transmission Network Charge	1584	$347,134	$31,682	$378,816
RSVA - Retail Transmission Connection Charge	1586	-$1,267,076	-$45,501	-$1,312,577
RSVA - Power	1588	$9,554,493	$49,174	$9,603,667
RSVA - Global Adjustment	1589	-$8,731,842	-$54,573	-$8,786,415
Recovery of Regulatory Asset Balances	1590	-$1,684,689	$201,324	-$1,483,365
Total Group 1 Excluding Global Adjustment – Account 1589				**$4,193,473**
Total Group 1				**-$4,592,942**

The balance of each Group 1 account approved for disposition shall be transferred to the applicable principal and interest carrying charge sub-accounts of Account 1595 pursuant to the requirements specified in Article 220, Account Descriptions, of the *Accounting Procedures Handbook for Electricity Distributors*. The date of the transfer must be the same as the effective date for the associated rates, generally, the start of the rate year. Essex should ensure these adjustments are included in the reporting period ending June 30, 2014 (Quarter 2).

Review and Disposition of LRAMVA Balance

The 2012 CDM Guidelines established the Lost Revenue Adjustment Mechanism Variance Account to capture, at the customer rate-class level, the difference between actual results from authorized CDM activities and the reduction for forecasted CDM activities included in the distributor's last Board-approved load forecast.

Distributors must apply for the disposition of the balance in the LRAMVA as part of their cost of service applications. Distributors may apply for the disposition of the balance in the LRAMVA on an annual basis, as part of their IRM rate applications, if the balance is deemed significant by the distributor.

Essex requested the recovery of an LRAMVA claim of $109,212, consisting of lost revenues in 2011 from CDM programs delivered in 2011 and persistence of 2011 programs in 2012 and lost revenues in 2012 from 2012 CDM programs.

Board staff noted that Essex had an updated load forecast approved as part of its 2010 cost-of-service application and that none of the lost revenues included in this request were subject to any previous approvals. Board staff submitted that the applied-for lost revenues are eligible for recovery.

VECC noted that for Essex's GS>50 kW rate class, the net demand (kW) reported for the Demand Response 3 ("DR3") program on a monthly basis is 1,749 kW, which accounts for approximately 94% of the class total of 1,852 kW. VECC submitted that the lost revenues from the GS>50 kW customers' participation in DR3 programs should not be included for recovery. VECC submitted that there was no evidence to indicate the program was activated, or if the program had been activated, there was no evidence to indicate the program had any significant effect on Essex's load, billing demand or distribution revenues.

In its reply submission, Essex stated that it has relied upon the final program results provided by the Ontario Power Authority ("OPA"), which is the best information available to calculate its lost revenues in the absence of access to DR3 activation data. Essex noted that any information related to the actual activations of DR3 programs is not provided by the OPA, nor is Essex provided with information about which customers are under contract. Essex submitted that its entire LRAMVA claim is related to OPA-Contracted Province-Wide CDM Programs and that all of the programs included in its LRAMVA claim have been reviewed and verified by the OPA. Essex submitted that the LRAMVA claim applied for, including the amounts for its DR3 program, is appropriate and ought to be approved by the Board as the best means to balance regulatory efficiency and the pursuit of perfection.

The Board approves the LRAMVA claim as submitted. Essex availed itself of OPA programs, and the results have been verified by the OPA. These claims shall be recovered over a one-year period from May 1, 2014 to April 30, 2015.

Rate Model

With this Decision and Rate Order, the Board is providing Essex with a rate model, applicable supporting models and a draft Tariff of Rates and Charges (Appendix A). The Board also reviewed the entries in the rate model to ensure that they were in accordance with the 2013 Board-approved Tariff of Rates and Charges and the rate model was adjusted, where applicable, to correct any discrepancies.

THE BOARD ORDERS THAT:

1. Essex's new distribution rates shall be effective May 1, 2014.

2. Essex shall review the draft Tariff of Rates and Charges set out in Appendix A and shall file with the Board, as applicable, a written confirmation of its completeness and accuracy, or provide a detailed explanation of any inaccuracies or missing information, within **7 days** of the date of issuance of this Decision and Rate Order.

3. If the Board does not receive a submission from Essex to the effect that inaccuracies were found or information was missing pursuant to item 2 of this Decision and Rate Order, the draft Tariff of Rates and Charges set out in Appendix A of this Decision and Rate Order will become final. Essex shall notify its customers of the rate changes no later than the delivery of the first bill reflecting the new rates.

4. If the Board receives a submission from Essex to the effect that inaccuracies were found or information was missing pursuant to item 2 of this Decision and Rate Order, the Board will consider the submission of Essex prior to issuing a final Tariff of Rates and Charges.

COST AWARDS

The Board will issue a separate decision on cost awards once the following steps are completed:

1. VECC shall submit their cost claims no later than **7 days** from the date of issuance of the final Rate Order.

2. Essex shall file with the Board and forward to (intervenor) any objections to the claimed costs within **21 days** from the date of issuance of the final Rate Order.

3. VECC shall file with the Board and forward to Essex any responses to any objections for cost claims within **28 days** from the date of issuance of the final Rate Order.

4. Essex shall pay the Board's costs incidental to this proceeding upon receipt of the Board's invoice.

All filings to the Board must quote file number **EB-2013-0128,** be made through the Board's web portal at https://www.pes.ontarioenergyboard.ca/eservice/ and consist of two paper copies and one electronic copy in searchable / unrestricted PDF format. Filings must clearly state the sender's name, postal address and telephone number, fax number and e-mail address. Parties must use the document naming conventions and document submission standards outlined in the RESS Document Guideline found at www.ontarioenergyboard.ca. If the web portal is not available parties may email their document to BoardSec@ontarioenergyboard.ca. Those who do not have internet access are required to submit all filings on a CD in PDF format, along with two paper copies. Those who do not have computer access are required to file 2 paper copies.

DATED at Toronto, March 13, 2014
ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

Appendix A

To Decision and Rate Order

Draft Tariff of Rates and Charges

Board File No: EB-2013-0128

DATED: March 13, 2014

Essex Powerlines Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2014

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2013-0128

RESIDENTIAL SERVICE CLASSIFICATION

This classification refers to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separately metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartments building also qualify as residential customers. Further servicing details are available in the distributor’s Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor’s Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	12.94
Rate Rider for Smart Metering Entity Charge - effective until October 31, 2018	$	0.79
Distribution Volumetric Rate	$/kWh	0.0152
Low Voltage Service Rate	$/kWh	0.0010
Rate Rider for Disposition of Deferral/Variance Accounts (2014) - effective until April 30, 2015	$/kWh	0.0099
Rate Rider for Disposition of Global Adjustment Account (2014) - effective until April 30, 2015 Applicable only for Non-RPP Customers	$/kWh	(0.0351)
Rate Rider for Application of Tax Change - effective until April 30, 2015	$/kWh	(0.0002)
Rate Rider for Recovery of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2014) - effective until April 30, 2015	$/kWh	0.0001
Retail Transmission Rate - Network Service Rate	$/kWh	0.0078
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0037

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0013
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Essex Powerlines Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2014

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2013-0128

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification refers to a non residential account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	33.87
Rate Rider for Smart Metering Entity Charge - effective until October 31, 2018	$	0.79
Distribution Volumetric Rate	$/kWh	0.0116
Low Voltage Service Rate	$/kWh	0.0010
Rate Rider for Disposition of Deferral/Variance Accounts (2014) - effective until April 30, 2015	$/kWh	0.0099
Rate Rider for Disposition of Global Adjustment Account (2014) - effective until April 30, 2015 Applicable only for Non-RPP Customers	$/kWh	(0.0351)
Rate Rider for Application of Tax Change - effective until April 30, 2015	$/kWh	(0.0001)
Rate Rider for Recovery of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2014) - effective until April 30, 2015	$/kWh	0.0004
Retail Transmission Rate - Network Service Rate	$/kWh	0.0068
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0035

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0013
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Essex Powerlines Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2014

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2013-0128

GENERAL SERVICE 50 TO 2,999 KW SERVICE CLASSIFICATION

This classification refers to a non residential account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 3,000 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	224.32
Distribution Volumetric Rate	$/kW	2.1306
Low Voltage Service Rate	$/kW	0.3506
Rate Rider for Disposition of Deferral/Variance Accounts (2014) - effective until April 30, 2015	$/kW	4.1666
Rate Rider for Disposition of Global Adjustment Account (2014) - effective until April 30, 2015 Applicable only for Non-RPP Customers	$/kW	(14.7463)
Rate Rider for Application of Tax Change - effective until April 30, 2015	$/kW	(0.0229)
Rate Rider for Recovery of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2014) (2011 & 2012 CDM Activities) - effective until April 30, 2015	$/kW	0.1012
Retail Transmission Rate - Network Service Rate	$/kW	2.7774
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.3887
Retail Transmission Rate - Network Service Rate - Interval Metered	$/kW	3.4214
Retail Transmission Rate - Line and Transformation Connection Service Rate - Interval Metered	$/kW	1.5398

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0013
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Essex Powerlines Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2014

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2013-0128

GENERAL SERVICE 3,000 TO 4,999 KW SERVICE CLASSIFICATION

This classification refers to a non residential account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 3,000 kW but less than 5,000 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor’s Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	1,473.70
Distribution Volumetric Rate	$/kW	1.3666
Low Voltage Service Rate	$/kW	0.4094
Rate Rider for Disposition of Deferral/Variance Accounts (2014) - effective until April 30, 2015	$/kW	13.3248
Rate Rider for Disposition of Global Adjustment Account (2014) - effective until April 30, 2015		
Applicable only for Non-RPP Customers	$/kW	(47.1592)
Rate Rider for Application of Tax Change - effective until April 30, 2015	$/kW	(0.0219)
Retail Transmission Rate - Network Service Rate	$/kW	3.4214
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.5398

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0013
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Essex Powerlines Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2014

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2013-0128

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification refers to an account whose monthly average peak demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The customer will provide detailed manufacturer information/documentation with regard to electrical consumption of the proposed unmetered load. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	9.19
Distribution Volumetric Rate	$/kWh	0.0286
Low Voltage Service Rate	$/kWh	0.0010
Rate Rider for Disposition of Deferral/Variance Accounts (2014) - effective until April 30, 2015	$/kWh	0.0099
Rate Rider for Disposition of Global Adjustment Account (2014) - effective until April 30, 2015		
Applicable only for Non-RPP Customers	$/kWh	(0.0351)
Rate Rider for Application of Tax Change - effective until April 30, 2015	$/kWh	(0.0003)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0068
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0035

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0013
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Essex Powerlines Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2014

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2013-0128

SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	3.29
Distribution Volumetric Rate	$/kW	9.4397
Low Voltage Service Rate	$/kW	0.2816
Rate Rider for Disposition of Deferral/Variance Accounts (2014) - effective until April 30, 2015	$/kW	3.6005
Rate Rider for Disposition of Global Adjustment Account (2014) - effective until April 30, 2015 Applicable only for Non-RPP Customers	$/kW	(12.7430)
Rate Rider for Application of Tax Change - effective until April 30, 2015	$/kW	(0.1049)
Retail Transmission Rate - Network Service Rate	$/kW	2.1383
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.0586

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0013
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Essex Powerlines Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2014

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2013-0128

STREET LIGHTING SERVICE CLASSIFICATION

This classification refers to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting operation, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape template. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	3.18
Distribution Volumetric Rate	$/kW	8.6188
Low Voltage Service Rate	$/kW	0.2798
Rate Rider for Disposition of Deferral/Variance Accounts (2014) - effective until April 30, 2015	$/kW	3.2604
Rate Rider for Disposition of Global Adjustment Account (2014) - effective until April 30, 2015		
Applicable only for Non-RPP Customers	$/kW	(11.5390)
Rate Rider for Application of Tax Change - effective until April 30, 2015	$/kW	(0.0955)
Retail Transmission Rate - Network Service Rate	$/kW	2.1084
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.0518

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0013
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Essex Powerlines Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2014

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2013-0128

microFIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	5.40

ALLOWANCES

Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.60)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

Essex Powerlines Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2014

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2013-0128

SPECIFIC SERVICE CHARGES

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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Customer Administration		
Arrears certificate	$	15.00
Statement of Account	$	15.00
Duplicate Invoices for previous billing	$	15.00
Request for other billing information	$	15.00
Easement Letter	$	15.00
Income Tax Letter	$	15.00
Account History	$	15.00
Returned cheque (plus bank charges)	$	15.00
Legal letter charge	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Special meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Non-Payment of Account		
Late Payment – per month	%	1.50
Late Payment – per annum	%	19.56
Collection of account charge – no disconnection	$	30.00
Collection of account charge – no disconnection – after regular hours	$	165.00
Disconnect/Reconnect Charge – At Meter – During Regular Hours	$	65.00
Disconnect/Reconnect Charge – At Meter – After Hours	$	185.00
Disconnect/Reconnect at pole – during regular hours	$	185.00
Disconnect/Reconnect at pole – after regular hours	$	415.00
Install/Remove load control device – during regular hours	$	65.00
Install/Remove load control device – after regular hours	$	185.00
Service call – customer owned equipment	$	30.00
Service call – after regular hours	$	165.00
Temporary service install & remove – overhead – no transformer	$	500.00
Temporary Service Install & Remove – Underground – No Transformer	$	300.00
Temporary Service – Install & remove – overhead – with transformer	$	1,000.00
Specific Charge for Access to the Power Poles - $/pole/year	$	22.35

Essex Powerlines Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2014

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EB-2013-0128

RETAIL SERVICE CHARGES (if applicable)

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

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Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity.

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	100.00
Monthly Fixed Charge, per retailer	$	20.00
Monthly Variable Charge, per customer, per retailer	$/cust.	0.50
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.30)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.25
Processing fee, per request, applied to the requesting party	$	0.50
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year	$	no charge
More than twice a year, per request (plus incremental delivery costs)	$	2.00

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0602
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0496

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Ontario Energy Board

Commission de l'énergie de l'Ontario

EB-2014-0291

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, (Schedule B);

AND IN THE MATTER OF a review of the capital contribution costs paid by Integrated Grain Processors Co-operative Inc. to Natural Resource Gas Limited pursuant to Sections 19 and 36 of the Act.

AND IN THE MATTER OF a hearing on the Board's own motion.

BEFORE: Christine Long
Presiding Member

Allison Duff
Board Member

DECISION AND ORDER
May 7, 2015

Natural Resource Gas Limited (NRG) is a privately owned utility regulated by the Ontario Energy Board (OEB) that sells and distributes natural gas within southern Ontario to approximately 7,000 customers. In 2008, NRG built a dedicated pipeline to serve the Integrated Grain Processors Co-operative Inc. (IGPC) ethanol plant after receiving leave to construct from the OEB (the Pipeline).

In a decision dated February 27, 2014 (the Original Decision)[1], the OEB awarded IGPC $150,000 for additional costs related to a letter of credit for the Pipeline. NRG wrote to

[1] EB-2012-0406/EB-2013-0081 Decision and Order dated February 27, 2014

the OEB asking it to review this award. The OEB decided to commence a review of the Original Decision by way of a motion to review (the Motion).

Background

The Pipeline required a capital contribution that was paid by IGPC to NRG. Under the terms of the Pipeline Cost Recovery Agreement (PCRA) between NRG and IGPC, IGPC was required to post a letter of credit matching the capital cost of the pipeline minus the capital contribution. The PCRA specified that the value of the letter of credit would be lowered every year to account for the depreciating value of the pipeline.

IGPC disputed some of the capital costs for the Pipeline identified by NRG and brought the issue before the OEB (the Original Proceeding)[2]. In that decision, the OEB determined the capital costs of the Pipeline for ratemaking purposes, adjusted the capital contribution from IGPC and the letter of credit amount accordingly. However, NRG did not adjust the letter of credit from 2008 to 2013.

IGPC claimed that it had to incur additional costs of approximately $150,000 to maintain the unadjusted letter of credit for five years[3]. In the Original Decision, the OEB awarded IGPC $150,000, to be paid by NRG, for the additional costs of maintaining the unadjusted letter of credit.

After receiving the Original Decision, NRG filed a letter asking that the OEB reverse its Original Decision regarding the $150,000 award to IGPC. NRG claimed that IGPC had not provided a detailed breakdown of the $150,000 in additional costs and that the OEB did not have the evidentiary basis to make its finding.

The OEB decided that revisiting the $150,000 award to IGPC would amount to a substantive change. Revisiting the dollar amount of the award could not be considered a typographical error, error of calculation or similar error contemplated by Rule 41.02 of the Board's *Rules of Practice and Procedure.* As a result, the OEB determined that it would re-hear the issue by way of a motion to review [4]. The OEB accepted all intervenors and adopted the evidence filed in the Original Proceeding. The Motion was

[2] EB-2012-0406/EB-2013-0081
[3] IGPC Pre-filed Evidence EB-2013-0081/EB-2012-0406, June 3, 2013, paragraph 152
[4] EB-2014-0291 Procedural Order No. 1

heard in writing and included argument-in-chief by NRG, submissions by parties and reply submission by NRG. The OEB indicated that submissions were not to include or refer to any new evidence that was not part of the evidentiary record of the Original Proceeding.

Motion to Review the $150,000 award

NRG submitted that the $150,000 award to IGPC was not supported by any evidence, was excessive to the point of being punitive and the cost was partially the responsibility of IGPC. NRG provided a calculation, based on a 1% interest rate for 19.5 months, and submitted that IGPC's carrying costs should have been approximately $20,000.

OEB staff submitted there was no doubt that IGPC had to incur some costs to maintain the unadjusted letter of credit. OEB staff did not agree with the $20,000 calculation but submitted that the award be reduced to $81,958 based on a 1.5% interest rate for 38 months. OEB staff indicated that the letter of credit was not a significant issue in the Original Proceeding, perhaps the reason why NRG did not counter IGPC's $150,000 estimate during that proceeding.

IGPC submitted that the OEB should not alter its Original Decision regarding the $150,000 award. According to IGPC, NRG did not object to the requested costs and OEB staff did not question the reasonableness of the $150,000 claim in the Original Proceeding yet both parties had ample opportunity to test the evidence and make submissions. IGPC submitted that NRG's motion was simply an attempt to re-litigate a decision which it did not like.

In reply argument, NRG dismissed the claim that it had ample opportunity to test the evidence in the Original Proceeding. NRG submitted that IGPC never provided a detailed breakdown of the incurred costs or any additional evidence. NRG submitted that IGPC had abandoned its position regarding the cost of maintaining letter of credit because it did not provide any additional evidence to support its $150,000 claim.

Board Findings

The Board has considered the submissions of all parties and has determined that the Original Decision stands. The Board will not vary the $150,000 award.

Rule 42.01of the Board's *Rules of Practice and Procedure* provides the following grounds for a motion to review: an error in fact, change in circumstances, new facts which have arisen or facts not in evidence that could not have been discovered by reasonable diligence at the time. Although this list is not exhaustive, the Board regards it as a good guide to the types of matters that are generally suitable for a motion to review. A motion to review should not be viewed as an opportunity to simply re-argue a case.

The Board has determined that none of criteria established in Rule 42.01 have been met. The Board finds that the calculations provided by NRG and OEB staff could have been provided or discovered by reasonable diligence in the original proceeding. There was a full discovery process in the Original Proceeding, and a motion to review is not meant to be an opportunity to ask questions on, or make submissions on, issues that could have been addressed in the first instance. If NRG had concerns about IGPC's claimed costs of $150,000, the appropriate time to pursue those concerns was in the Original Proceeding. Instead, IGPC's evidence (i.e. its claim that it had incurred costs of $150,000) went unchallenged. The Board can dismiss the motion for this reason alone.

The Board has also reviewed the evidence in the Original Proceeding. The $150,000 estimate of "additional costs" appears to have included both financing and legal costs, not just the carrying costs for the letter of credit. IGPC indicates it incurred "legal and other costs" in its interrogatory response #2 filed on October 28, 2013 and filed copies of letters, which in turn referred to telephone conversations, between IGPC's lawyer and NRG[5]. Although proposed award calculations were provided in the submissions of NRG and OEB staff, those calculations relate only to financing costs for carrying the letter of credit, not the legal costs of IGPC trying to resolve the issue with NRG.

Further, this panel does not find merit in NRG's comparison of the $150,000 award to the insurance costs claimed by NRG for the capital cost of the Pipeline. The Original Decision disallowed the recovery of insurance costs as the Board was not convinced that any additional insurance costs had been incurred. In contrast, the Board had no doubt that IGPC had incurred additional costs to maintain the unadjusted letter of credit for 5 years.

Costs of Proceeding

In its argument-in-chief, NRG requested costs to participate in this proceeding. IGPC in its submission also sought costs for this proceeding. OEB staff argued that no party

[5] Eb-2012-0406 / EB-2013-0081, IGPC interrogatory response #2

should be awarded costs. OEB staff indicated that the dispute arose because NRG did not adjust the letter of credit in accordance with the PCRA. If NRG had adjusted the letter of credit, no additional costs would have been incurred by IGPC and the matter would not have been brought forward to the Board.

In reply argument, NRG submitted that OEB staff had conflated the issues in the original proceeding with the issues in the Motion. NRG did not dispute its obligation regarding the letter of credit; NRG disputed the quantum of the IGPC award. NRG submitted that its dispute was made on a principled basis in an attempt to correct an error made by the Board.

NRG indicated that if IGPC had provided a detailed breakdown in the Original Proceeding, all parties would have had the opportunity to assess the appropriateness of the claim and the Motion would not have been necessary.

Board Findings

The Board finds that NRG and IGPC will be responsible for their own costs of participating in the Motion. No cost awards will be made. The Board finds both parties participated equally in the Original Proceeding by filing evidence and submissions and both parties participated equally in the Motion.

As the Board initiated the Motion, there is no applicant in this proceeding to pay cost awards, the standard practice at the OEB. Accordingly, the Board will absorb its own incidental costs in the Motion and will not invoice either party.

ADDRESS

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Attention: Board Secretary

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DATED at Toronto May 7, 2015

ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

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Ontario Energy Board

Commission de l'énergie de l'Ontario

EB-2012-0206

IN THE MATTER OF the *Ontario Energy Board Act 1998*, S.O.1998, c.15, (Schedule B);

AND IN THE MATTER OF an Application by Union Gas Limited for an Order or Orders amending or varying the rate or rates charged to customers as of October 1, 2011;

AND IN THE MATTER OF a proceeding commenced by the Ontario Energy Board on its own motion to determine the accuracy of the calculation of margin sharing related to Deferral Account 179-70 - Short-Term Storage and Other Balancing Services.

NOTICE OF MOTION TO REVIEW, NOTICE OF MOTION HEARING AND PROCEDURAL ORDER NO. 1

May 2, 2012

Union Gas Limited ("Union") filed an application dated April 18, 2011 with the Ontario Energy Board (the "Board") under section 36 of the *Ontario Energy Board Act, 1998*, S.O. c.15, Schedule B, for an order of the Board amending or varying the rate or rates charged to customers as of October 1, 2011 in connection with the sharing of 2010 earnings under the incentive rate mechanism approved by the Board as well as final disposition of 2010 year-end deferral account and other balances (the "Application"). The Board assigned file number EB-2011-0038 to the Application.

On September 19-21 2011, the Board held a hearing on all matters in that proceeding and the Board issued its Decision and Order on January 20, 2012. The Board directed Union to file a Draft Rate Order which reflected the Board's findings in its Decision.

The Board received submissions from parties contesting Union's Draft Rate Order with respect to the Short-Term Storage and Other Balancing Services Deferral Account ("Short-Term Storage Account"). The Board issued its Decision and Order on the Draft

Rate Order on February 29, 2012, directing Union to file a revised Draft Rate Order reflecting the Board's determination on the matter. The Board noted that it would review the revised Draft Rate Order to confirm that all the necessary changes were made and would subsequently issue a Final Rate Order.

Union filed a revised Draft Rate Order on March 2, 2012. The Board issued its Final Rate Order on March 8, 2012 approving Union's Draft Rate Order as filed.

By letter dated March 27, 2012, Canadian Manufacturers & Exporters ("CME") (an intervenor in the proceeding) noted that an issue had arisen in the EB-2011-0038 proceeding regarding the calculation of margin sharing in the Short-Term Storage Account. CME indicated that the correct amount to be credited to ratepayers should be \$3.824 million (as opposed to the \$0.831 million credit approved by the Board in the EB-2011-0038 Final Rate Order). CME requested that the Board address this error by making an adjustment to the margin sharing calculation under Rule 43.02 of the Board's *Rules of Practice and Procedure*. Union filed a letter responding to CME's letter on April 5, 2012, CME filed a subsequent letter on April 16, 2012, and Union filed a final letter on April 19, 2012.

The Board has determined that the correction requested by CME in regards to the margin sharing calculation in the Short-Term Storage Account would not, if substantiated, be allowable under Rule 43.02 of the Board's *Rules of Practice and Procedure* (the "Rules"). The Board is, however, of the view that issues have been raised with respect to the calculation of short-term storage margin sharing which warrant further review by the Board. The Board has therefore determined that it will commence a review proceeding on its own motion pursuant to Rule 43.01 of the Rules to review its EB-2011-0038 Decision and Rate Order as it relates to the issue of calculating the amount of margin sharing in the Short-Term Storage Account. The Board has assigned Board File No. EB-2012-0206 to this proceeding.

The Board adopts the intervenors in the EB-2011-0038 proceeding as intervenors in this proceeding. Intervenors that were eligible for costs in that proceeding are deemed eligible for costs in this proceeding. A list of intervenors for EB-2012-0206 is attached as Appendix A to this order.

The Board will incorporate the four letters noted above (two from CME and two from Union) as submissions in this proceeding. All intervenors and Union will be given an opportunity to make additional submissions on this single issue.

Accordingly, the Board will make provisions for the following procedural matters. Please be aware that further procedural orders may be issued from time to time.

THE BOARD ORDERS THAT

1. All parties (Board staff, intervenors, and Union) shall file any submissions on the calculation of margin sharing in the Short-Term Storage Account on or before **May 11, 2012**.

All filings to the Board must quote file number **EB-2012-0206**, be made through the Board's web portal at www.errr.ontarioenergyboard.ca, and consist of two paper copies and one electronic copy in searchable / unrestricted PDF format. Filings must clearly state the sender's name, postal address and telephone number, fax number and e-mail address. Please use the document naming conventions and document submission standards outlined in the RESS Document Guideline found at www.ontarioenergyboard.ca. If the web portal is not available you may email your document to the BoardSec@ontarioenergyboard.ca. Those who do not have internet access are required to submit all filings on a CD in PDF format, along with two paper copies. Those who do not have computer access are required to file seven paper copies. If you have submitted through the Board's web portal an e-mail is not required.

All parties must also provide the Case Manager, Lawrie Gluck, Lawrie.gluck@ontarioenergyboard.ca with an electronic copy of all comments and correspondence related to this case.

ISSUED at Toronto, May 2, 2012

ONTARIO ENERGY BOARD

Original Signed By

Kirsten Walli
Board Secretary

APPENDIX A

NOTICE OF WRITTEN HEARING AND PROCEDURAL ORDER NO. 1

LIST OF INTERVENORS

BOARD FILE NO. EB-2012-0206

DATED May 2, 2012

Ontario Energy Board

EB-2012-0206

APPLICANT & LIST OF INTERVENORS

May 2, 2012

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INTERVENORS	Rep. and Address for Service
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EB-2012-0165

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, (Schedule B);

AND IN THE MATTER OF an application by Sioux Lookout Hydro Inc. for an order approving just and reasonable rates and other charges for electricity distribution to be effective May 1, 2013.

BEFORE: Paula Conboy
Presiding Member

Allison Duff
Member

DECISION AND ORDER
August 22, 2013

Sioux Lookout Hydro Inc. ("SLHI") filed an application with the Ontario Energy Board on February 22, 2013 under section 78 of the *Ontario Energy Board Act*, *1998*, seeking approval for changes to the rates that SLHI charges for electricity distribution, effective May 1, 2013. The Board issued a Notice of Application and Hearing on March 7, 2013.

The Vulnerable Energy Consumers Coalition ("VECC") and an individual, Mr. Douglas Shields, applied for and were granted intervenor status. VECC was also granted cost award eligibility. The hearing process included interrogatories, supplemental interrogatories, and written submissions. Mr. Shields filed a submission on May 29, 2013. Board staff and VECC filed submissions on June 28, 2013. SLHI filed its reply submission on July 5, 2013.

While the Board has considered the entire record in this proceeding, it has made reference only to the evidence necessary to provide context to its findings. The

Decision does not reference parts of SLHI's application which are not in dispute. The following issues are dealt with in this Decision:

- Effective Date for Rates;
- Capital Expenditures and Rate Base;
- Operating Revenues;
- Operating Expenses;
- Cost of Capital;
- Cost Allocation;
- Rate Design;
- Deferral and Variance Accounts;
- Stranded Meters;
- Updated RRRP, WMSC and Smart Metering Entity Charges;
- Submission from Mr Shields; and
- Implementation.

Effective Date for Rates

On August 3, 2012, SLHI notified the Board that, due to unforeseen circumstances triggered by the retirement of its President/CEO, subsequent restructuring and resource allocation, the filing of its 2013 cost of service application would be delayed. SLHI filed its application on February 22, 2013 and requested an effective date for rates of May 1, 2013. SLHI's current rates were declared interim by the Board, pending a determination of this matter in this proceeding.

Board staff submitted the reasons provided by SLHI to support the delay in filing its 2013 cost of service application should be part of normal business planning. Board staff further noted it has been Board practice, in the case of late filings, to have as an effective date the month following the issuance of the Board's Decision and Order. VECC submitted no compelling reason was provided by SLHI to justify an effective date of May 1, 2013.

In its reply submission, SLHI submitted that small utilities are faced with the same pressures to conform to rules and regulations as large utilities but have limited resources to do so. SLHI further noted that due to transition issues faced by the company and the smart meter application process, SLHI was unable to dedicate time to prepare the application until later in 2012. SLHI indicated the added cost of hiring an outside consultant to prepare its application to meet the filing deadline would not be in the best interest of the company.

Board Findings

The Board will not accept SLHI's proposal to make rates effective on May 1, 2013 or allow for recovery of any foregone revenue. The Board established an August 31, 2012 target date for filing 2013 applications to allow sufficient time to complete the proceeding and issue a final rate order before May 1, 2013. The Board appreciates that SLHI has limited resources as it is a smaller utility, but finds the reasons that SLHI provided for its delay are part of normal business planning and dealing with them should be within the company's control.

A regulated utility must consider the lead time required to plan and meet its regulatory obligations and integrate those plans into its workflows. As a regulated for-profit monopoly, a core element of the company's business is its engagement with the regulatory process. The preparation of a conventional cost of service application should be part of the ongoing business process and should not place an undue burden on the utility's staff or resources.

SLHI filed its application on February 22, 2013, 6 months after the Board's target date. The Board does not consider it reasonable for ratepayers to bear the associated risk or cost of the 6-month filing delay. SHLI's new rates will be effective September 1, 2013, which is 4 months after the proposed May 1, 2013 date.

Capital Expenditures and Rate Base

SLHI proposed a 2013 test year rate base of $6,147,305 which includes $4,934,794 in average net fixed assets. This compares to average net fixed assets of $ 4,615,526 in 2008. Board staff and VECC took no issue with SLHI's proposed rate base.

In 2012, SLHI changed its capitalization and depreciation expense polices which included the half-year rule for the first year of capital additions. As a result, SLHI indicated it retroactively applied the half-year rule to capital asset additions from 2007-2012 to reflect its new accounting policy "as per OEB Guidelines". Further, SLHI restated rate base and depreciation expenses accordingly and reflected the changes in Deferral Account 1576.

Board Findings

The Board accepts SLHI's proposed rate base and capital additions. However, the Board is concerned that SLHI retroactively adopted the half-year rule for capital asset additions back to 2007. As explained in its Kingston Hydro Decision EB-2010-0136, restatement of historical rate base is not appropriate for cost of service applications. The intent of the half-year rule is to capture the fact that not all capital assets are put into service on January 1 of the test year. The Board's application filing requirements are forward looking and are meant to outline the rate setting methodology for future test years, not to be used to retroactively restate rate base.

While reluctant to depart from the rate making principle, the Board has considered the specific circumstances in this case and notes the resulting rate impact is not material to justify the effort to SLHI of recalculating depreciation, rate base and Account 1576 to reverse and correct for the restatement.

Working Capital Allowance

SLHI proposed a 13% Working Capital Allowance ("WCA"), equal to the Board default rate. Board staff submitted that SLHI has followed the Board's guidelines in determining the WCA and took no issue with SLHI's proposal.

VECC proposed a rate of 12%. VECC noted that SLHI bills its customers monthly while the Board's default rate was established when most utilities offered bi-monthly billing. VECC submitted that utilities performing monthly billing have a larger cash flow than bi-monthly billing utilities and therefore a lower need for working capital. As SLHI did not perform a lead-lag study, stating the cost would exceed the benefit of conducting a study, VECC referenced lead-lag studies completed by monthly-billing utilities that lead to working capital requirements of 11.4% of controllable costs.

Board Findings

The Board accepts SLHI's proposal to use a 13% WCA consistent with Board policy. The Board finds no compelling reason to depart from its default rate. The Board is reluctant to adopt the results of lead-lag studies from one utility to another or reference the WCA from settlement agreements without a thorough analysis of the circumstances for each utility. In accepting settlement agreements, the Board has made it clear that there is no precedential value in the individual components of a settlement agreement as all settlements contain trade-offs.

Operating Revenues

Customer Forecast
SLHI forecast its customer count for 2013 by applying the historical geometric mean customer growth rate from 2003-2011 to the actual 2011 count for each customer class. In its interrogatory responses, SLHI revised its forecast for the GS<50 kW and GS>50 kW rate classes by adopting the actual average customer counts for 2012 of 386 and 51 respectively, for a total 2013 forecast of 3,293 customers.

VECC submitted the 2013 forecast should be based on the 2012 year-end customer count for the GS<50 kW, GS>50 kW and the USL customer classes which would increase the total customer count to 3,297.

<u>Board Findings</u>
The Board accepts SLHI's proposed 2013 customer count by rate class. While the differences between SLHI's and VECC's proposals are small, the Board finds no compelling reason to diverge from the company's forecast given SLHI's knowledge of its own customer base.

Load Forecast
SLHI forecast 2013 power purchases to be 77.7 GWh, based on the 12-year weather normal average and using a multivariate regression model. Power purchases were regressed against explanatory variables of economic and weather-related factors. SLHI also included a variable to reflect the loss of demand from the closed Pulp and Paper Mill in its service area. A CDM variable was tried but discarded in the final model as its coefficient was not statistically significant.

SLHI divided the 77.7 GWh power purchase forecast by 1.0446, which represents the average loss factor from 2003 to 2011, to determine the total billed energy forecast of 74.4 GWh for 2013. VECC agreed with SLHI's proposal.

Board staff submitted that the 2013 power purchase forecast should be 76.1 GWh based on the model in interrogatory response 3-Staff-34s. Board staff considered this model to be preferable given its improved model statistics from excluding the intercept and removing the Pulp and Paper Mill flag. Board staff agreed with SLHI that a power purchase forecast should be adjusted by the loss factor to determine the billed load forecast. SLHI did not file a reply to Board staff's submission.

Board Findings

The Board accepts the power purchase forecast of 76.1 GWh given the improved model statistics. The Board notes this load forecast will need to factor into the draft Rate Order through the working capital allowance, cost allocation and billing determinants. The Board approves a 2013 load forecast of 72.85 GWh, after adjusting for the loss factor of 1.0446.

The CDM Adjustment to the Load Forecast

SLHI proposed a load forecast adjustment of 1,024,760 kWh to account for the impact of new CDM programs introduced after 2011, the historical period on which the load forecast model was built. SLHI included the full-year, net impact of energy savings from the 2012 and 2013 CDM programs.

Board staff submitted the CDM adjustment should be 799,318 kWh and adjusted up for the loss factor. In its recommended calculation, Board staff included the half-year impact of the 2011 and 2013 programs and the full-year impact of the 2012 program. Board staff indicated the regression models used to derive the load forecast did not include a CDM variable; therefore, an adjustment for the full-year impact of 2011 CDM program was required as only half the 2011 program results were in the underlying data.

VECC submitted the CDM adjustment should be 768,570 kWh to reflect the net, full-year impact of the 2012 CDM program and a half-year impact of the 2013 CDM program. VECC agreed with SLHI that the regression model already incorporated the impact of the 2011 CDM programs and did not support the 2011 adjustment proposed by Board staff.

Board Findings

The Board approves a CDM adjustment of 768,570 kWh to be deducted from the 2013 load forecast. To determine the total CDM adjustment, the Board considered the contributing effect of each CDM program year.

The Board agrees with the half-year impact of the 2013 CDM program for the CDM adjustment proposed by Board staff and VECC, as it is the first year of the program. As stated in the Board's Centre Wellington Decision (EB-2012-0113) "program results build over the year and are not fully realized from day one". The 2013 net impact is 256,190 kWh.

The Board agrees with the full-year impact of 2012 CDM programs for the CDM adjustment as proposed by SLHI, Board staff and VECC. The 2012 net impact is 512,380 kWh.

The Board does not agree with the inclusion of the half-year impact of the 2011 CDM program as proposed by Board staff. The Board agrees with SLHI and VECC that CDM impacts were embedded in the data and incorporated into the regression model. If an explicit CDM variable was disregarded from the model as non-predictive, a subsequent compensating CDM adjustment is not considered appropriate.

The Board does not find it necessary to alter the total 2013 CDM adjustment by the loss factor as proposed by Board staff. The power purchase forecast was adjusted by the loss factor to convert to an energy billed equivalent. However, CDM program targets are based on energy savings and do not require a loss factor adjustment to be deducted from the energy billed forecast.

LRAM

A CDM impact adjustment is also identified for the purpose of determining the lost revenue adjustment mechanism (“LRAM”) value. SLHI proposed an LRAM value of 1,086,257 kWh equal to the total annualized net CDM savings for the 2011, 2012 and 2013 CDM programs. Board staff and VECC supported SLHI’s proposal. Further, Board staff and VECC submitted it was acceptable for the Board to approve an LRAM value that differed from the CDM adjustment to the 2013 load forecast.

Board Findings

The Board accepts SLHI’s proposal for the LRAM value.

Other Revenues

SLHI forecast Other Operating Revenues of $129,025 for 2013. Board staff submitted SLHI had adequately explained and supported its proposal. VECC expressed a concern that $20,002 in Interest and Dividend Income, a component of Other Operating Revenues, may include interest revenue associated with variance accounts. In its reply submission, SLHI confirmed revenue associated with variance accounts is included in the $20,002.

Board Findings

The Board accepts SLHI's forecast for Other Operating Revenues of $129,025. While interest revenue associated with variance accounts should not be included in Other Operating Revenue, the Board does not expect SLHI to remove the associated interest revenue as the 2013 dollar impact is immaterial. The Board directs SLHI to adjust its accounting practice to exclude any interest revenue related to variance accounts on a forward basis.

Operating Expenses

SLHI proposed an operations, maintenance and administration expense ("OM&A") budget of $1,554,419 for 2013. The proposed OM&A represents a 38.8% over its 2008 Board-approved OM&A or a 35.6% increase over its 2008 actual OM&A.

SLHI provided explanations for cumulative changes in OM&A by category and cost driver. Overall OM&A remained relatively stable from 2008 to 2011. In the 2012 bridge year, however, the budget is forecast to increase by 36.3% over the 2011 actual OM&A before decreasing by 2.6% in 2013. Further details are provided in the following table.

Year	2008 Board approved	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Bridge Forecast (CGAAP)	2012 Bridge Forecast (CGAAP amended)	2013 Test Forecast (CGAAP amended)
Maintenance	87,281	91,130	94,702	116,678	106,053	320,616	320,616	201,605
Change from 2008 actual							252%	121%
Operations	421,827	426,324	396,303	493,191	479,053	539,851	584.640	628,363
Change from 2008 actual							36%	47%
Billing & Collecting	349,826	365,700	381,340	310,460	265,561	298,102	298,102	316,965
Change from 2008 actual							-18%	-13%
Admin and General	260,892	263,826	267,718	240,621	319,541	386,819	391,805	407,460
Change from 2008 actual							49%	54%
Total OM&A	$1,119,826	$1,146,980	$1,140,063	$1,160,950	$1,170,208	$1,545,388	$1,595,163	$1,554,419
Annual change			-0.6%	1.8%	0.8%	32.1%	36.3%	-2.6%
Change From 2008 actual							39.1%	35.6%

SLHI identified the cost drivers for the increases in OM&A as follows:

- Increased tree trimming expenses;
- On-going expenses related to the maintenance of smart meters (accompanied by reduction in meter reading re-verification costs);
- Training costs related to defensive driving and AZ training required to be able to float large equipment to work sites;
- Transformer testing in compliance with Ontario Regulation 362;
- Costs due to organizational restructuring resulting from the retirement of the President/CEO;
- Increased regulatory expenses;
- Increase in bad debt expense as a result of two businesses in the area going out of business and subsequently leaving the area;
- One-time costs due to a confidential human resource issue related to expenditures ($84,746) incurred in 2012 comprising severance package and consulting fees concerning an outgoing employee (lineman). SLHI proposed recovery of this cost over a 4 year period starting in 2013; and
- Change in capitalization policy resulting from the amendment to CGAAP in 2012, resulted in an increase in OM&A of $39,127.

SLHI proposed a staff complement of 9 full-time employees for 2013, an increase over its 8 full-time employees from 2008 to 2011. SLHI's structural reorganization involved the retirement of its President/CEO in 2012, the reclassification of its meter-reader position to groundsman, the retirement of a lineman and the hiring of two linemen replacements as part of a succession planning exercise. Board staff noted the staff complement should reduce when the current linemen retire. VECC noted that, while it is not explicitly stated, the retention and reclassification of the former meter reader implies the savings from reduced meter reading costs have not actually occurred.

SLHI provided analyses of its OM&A costs per customer and per FTEE. Board staff and VECC noted SLHI is a high-cost utility compared to other utilities in its cohort.

In reply, SLHI submitted a comparison of OM&A per customer and per FTEE across utilities was not fully indicative of the company's operational efficiencies. SLHI further submitted that the OM&A comparisons do not consider other differences, specifically SLHI's large rural area, service territory or kilometers of line.

Board staff agreed with SLHI's 2013 OM&A with the exception of its proposal to recover $84,746 of one-time human resource expenses in 2013 to 2017. Board staff submitted the $84,746 should be absorbed by SLHI as the expense was incurred in 2012 and commensurate with the normal cost of running a business. VECC submitted the expense should be considered out-of-period for a 2013 rate application and not recoverable in 2013 rates.

VECC recommended a budget reduction to $1.35 million based on an envelope approach or an "expected growth test". VECC indicated the purpose of its test is to understand the reasonableness of cost increases since the last cost of service application. Accordingly, VECC took into consideration the cost of new customer additions, inflation, productivity and the cost of incremental responsibilities. VECC argued the envelope approach to OM&A provides utility management with some discretion to adjust elements of its OM&A budget without adversely affecting plant investments or utility service. VECC made a number of observations regarding specific expense items to support its budget reduction proposal.

SLHI disagreed with VECC's envelope approach. SLHI indicated it went through considerable effort to supply Board Staff and VECC with explanations and update its 2012 costs and 2013 forecasts. To simply administer a generic adjustment to the proposed OM&A, in SLHI's opinion, would not be appropriate.

Board Findings

SLHI's proposed OM&A increase from 2008 actual to 2013 test year of 35.6% or $407,439 is driven primarily by the increase from 2011 to 2012. The Board appreciates a percentage change must be reviewed in context of the dollars involved. However, the Board has determined SLHI has not sufficiently justified this level of increase. The 2013 Board approved OM&A is $1,421,245. The reasons for the OM&A reduction are set out below.

SLHI explained its budgeting approach and stated that its Board of Directors reviews and approves the budget. The evidence shows the budget is based on historical spending levels and increased to reflect additional activities and increased costs. However, there appeared to be little analysis of the reasonableness of the overall OM&A budget in terms of its effect on rates and ratepayers. In addition, there is no evidence of cost constraints imposed internally or by SLHI's Board of Directors to drive efficiencies. The only cost efficiency appears to have come in the area of meter reading, which has been offset by reclassifying the meter reader to a groundsman. Demonstrating a sufficient level of review of its overall budget level, including the magnitude of the increase is particularly relevant given SLHI appears to be a high-cost utility compared to its peers. SLHI presented information on OM&A per square kilometer and per km of line for the first time in reply argument. It is generally inappropriate in a cost of service proceeding to rely on evidence presented through submission as the calculations cannot be tested. As such, the Board is unable to place any weight on those calculations in its determination.

A significant amount of the requested increase relates to the addition of a full-time linesman for succession planning purposes. The Board accepts there has to be a brief period of overlap when new linesmen are brought into the workforce. However, the Board finds there is insufficient explanation and justification as to why ratepayers should fund OM&A increases to account for the restructuring required due to the retirement of the President/CEO in 2012. In particular, SLHI identified persisting costs “due to Organizational restructuring” as a cost driver that resulted in an OM&A increase of $73,279 in 2012 and a further increase of $89,458 in 2013. These persisting expenses are in addition to the one-time HR related expense of $84,746 incurred in 2012 (further discussed below). It is unclear whether the retention and reclassification of the meter reader employee was included in these increases or incremental. The Board is concerned with the level of increase under the umbrella of “succession planning” and “restructuring” SLHI proposes to recover from ratepayers, when there are no quantifiable benefits to customers or service reliability as a direct result of these expenditures.

In the absence of sufficient evidence to substantiate the proposed level of OM&A expense increase, the Board must determine the appropriate level of reduction. The Board finds merit in VECC’s envelope approach to deriving an increase that reflects inflation, customer growth, productivity, and efficiency improvements. The Board will adopt an envelope approach and will derive an approved OM&A level based on 2011 actuals. While VECC’s submission was based on the 2008 Board approved level, the Board finds it more appropriate to derive the 2013 level from the most recent actual year. To the 2011 actual OM&A, the Board will apply an escalation factor which is representative of customer growth and inflation over the longer period. The number of customers SLHI services has decreased from 2008 to 2013, and the Board will assign a zero escalation factor related to customer growth. Inflation has increased by an average of 1.7% annually over the longer period. In recognition that costs do not increase one-for-one with growth in customers and in recognition that the company should be accommodating incremental expenses through efficiency improvements, the Board will reduce this escalation factor. The Board finds that a compound escalation factor of 1.3% (1.7% - 0.4% which represents SLHI's placement in its efficiency cohort) from the 2011 actual is appropriate. This results in a 2013 OM&A budget of $1,200,831.

The Board's approval of just and reasonable rates takes into account the expectation that a distributor will exercise efficiencies yet the Board recognizes that distributors should be able to recover costs for any incremental responsibilities since the time of its last cost of service rebasing. As a result, the Board will make an upward adjustment to the OM&A calculation of $39,127 related to SLHI's change in capitalization policy, $81,287 related to the ongoing costs for smart meters and LEAP funding, and $100,000 to allow for the increase in staff. This increases the 2013 OM&A budget to $1,421,245, a reduction of $133,174 compared to SLHI's 2013 OM&A proposal of $1,554,419. The Board finds this OM&A budget sufficient to accommodate inflation, customer growth, and incremental expenditures.

The Board's mandate is not to direct an applicant on how to manage its utility and therefore the Board will not comment on the specific areas in which SLHI should curtail OM&A spending. However, the Board agrees with Board staff and VECC that the $84,746 human resource cost in 2012 is an out-of-period expense for 2013. The recovery of the $84,746 in 2013-2017 is inappropriate as it is contrary to the rule against retroactive rate making.

Cost of Capital

In its application, SLHI estimated a Cost of Capital of 5.66%, based on a deemed capital structure of 60% debt (56% long-term debt and 4% short-term debt) and 40% equity. SLHI applied a return on equity of 9.12% and a deemed short-term debt rate of 2.08%. SLHI proposed a long-term debt rate of 3.44% based on two bank loans, one loan with a principal amount of $1,763,851 at a rate of 3.0% and the second with a principal amount of $618,942 and an interest rate of 4.70%

The Board updated its cost of capital parameters for rates effective May 1, 2013 on February 14, 2013 as shown in the following table.

Board's Cost of Capital Parameters	Rate
Return on Equity	8.98%
Deemed Short-term Debt	2.07%
Deemed Long-Term Debt	4.12%

Through the interrogatory process, SLHI updated its cost of capital parameters and calculated a weighted average cost of capital of 5.98%. Board staff agreed with SLHI's proposed 5.98%. VECC noted SLHI had changed its long-term debt rate from 3.44% to the Board's default value of 4.12%. As no change had been made to SLHI's third-party loan agreements, VECC submitted SHLI should revert back to the originally filed 3.44% rate for long-term debt based on its evidence of third-party loans.

In reply, SLHI submitted the change to the long-term debt rate was simply made in response to Board staff and VECC's interrogatories to update the cost of capital parameters to the most recent Board approved rates.

Board Findings

The Board's finds it appropriate for SLHI use the Board's deemed cost of capital rates of 8.98% for equity and 2.07% for short-term debt However, the Board agrees with VECC that SLHI's long-term debt rate should be 3.44% based on its loan contracts. The Board's default rate of 4.12% should only be used in the absence of third-party loans, as indicated in the Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, Dec.11, 2009. As a result, the Board approves a 5.60% cost of capital in 2013.

Cost Allocation

SLHI conducted an updated Cost Allocation Study (the "Study"), provided revenue-to-cost ("R/C") ratios resulting from the Study and proposed R/C ratios for 2013.

R/C Ratios
2010 IRM and 2013 Cost Allocation Study and Proposed (updated via interrogatory process)

Customer Class	Range (%)		2010 IRM Application	2013 Cost Allocation Study	2013 Proposed
	Low	High			
Residential	85	115	98.09%	90.34%	96.35%
GS < 50 kW	80	120	96.26%	115.15%	109.85%
GS 50-4999 kW	80	120	129.16%	138.31%	119.84%
Street Lighting	70	120	70.00%	83.08%	74.91%
Unmetered Scattered Load	80	120	98.29%	81.30%	80.96%

Board staff took issue with SLHI's proposed ratios for SL and USL. While the proposed R/C ratios were within the Board's target range for each class, the resulting ratios moved further away from 100% and therefore, were not appropriate in Board staff's opinion. Board staff submitted the R/C ratios for the SL and USL classes should be set at 83.08% and 81.30% as derived by the Study with the additional revenue used to further decrease the ratio for the GS>50 kW class.

In VECC's view the cost allocation methodology, as applied by Sioux Lookout had not improved to warrant moving the ratio for the GS<50 kW class closer to one. VECC submitted ratios should be changed only if necessary to maintain revenue neutrality which was not the case in the current circumstances

In addition, VECC took issue with SLHI's proposals to reduce the R/C ratios for SL and USL further away from unity as the proposals contravened the Board's November 2007 Report, EB- 2007-0667 "Application of Cost Allocation for Electricity Distributors". VECC provided two proposals to increase the R/C ratios for the Residential, SL and USL classes:

1. Increase the ratios for SL and USL up to the status quo value for Residential and, then, increase all three ratios in tandem until revenue neutrality is achieved.
2. Adjust the ratios for SL and USL by two percentage points for every one percentage point increase applied to Residential.

VECC noted that the first approach was preferable from a strict R/C ratio setting perspective as adjustments would be applied first to ratios furthest from unity.

In its reply submission, SLHI agreed with Board Staff and indicated that if the Board decided the SL and USL class R/C ratios be should 83.08% and 81.30% respectively, it would be appropriate to further decrease the GS>50 kW class revenue requirement in order to maintain revenue neutrality.

<u>Board Findings</u>
The Board accepts SLHI's proposed R/C ratios for residential, GS<50 kW and GS> 50 kW and its revised proposal to adopt the R/C ratios produced by the Study of 83.03% for SL and 81.30% for the USL classes. The additional revenue from the SL and USL customer classes will be applied to the GS>50 kW customer class to further reduce its R/C ratio. The Board does not agree with VECC's proposal to increase the SL and USL

ratios to the Residential ratio of 90.34% and then increase all three ratios in tandem. The Board finds VECC's proposal dismisses the class-specific R/C ratios provided by the Study.

Rate Design

Fixed/Variable Split

SLHI proposed to maintain the same fixed/variable ratios in its current 2012 rates for all customer classes. Board staff took no issue with SLHI's proposal.

VECC disagreed with SLHI's proposal as the fixed charges for the GS<50 kW and GS>50 kW classes exceeded the Study's ceiling values. VECC submitted the fixed service charges for these classes should be capped at the current 2012 rates, not the fixed/variable ratios.

<u>Board Findings</u>

The Board accepts SLHI's proposal to maintain the fixed/variable ratios. The Board notes this is consistent with other decisions[1] in which it has approved applications to increase monthly service charge that were already above the cost allocation ceiling, provided that the increase would not result in a higher revenue from the fixed charge relative to the volumetric charge.

Rate Mitigation

SLHI provided bill impact analysis in its application, updated though interrogatories.

	Total Bill Impact %	
	Provided in Application	Updated through interrogatories
Residential	6.53%	6.14%
GS < 50 kW	2.71%	2.51%
GS 50 to 4,999 kW	0.52%	(0.03%)
Street Lighting	2.48%	1.79%
Unmetered Scattered Load	9.99%	10.46%

[1] Decision on Hydro One Brampton Inc. (EB-2010-0132), p. 38. Decision on Lakeland Power Distribution Ltd. (EB-2008-0234), p.29-30. Decision on London Hydro Inc. (EB-208-0235), p.42-43.

In reply, SLHI submitted that if the Board set the R/C ratio to 83.08% for the SL class, the rate impact would be 11.41%. SLHI submitted the adjustment could be made over two years to mitigate the impact. The SL class R/C ratio would be 76.54% in the first year and 83.08% in the second year.

With respect to the USL class, SLHI indicated that if the Board set the R/C ratio to 81.30% the rate impact would be 13.91%. SLHI noted the total revenue requirement for the year was only $680 and submitted the amount was not significant enough to warrant rate mitigation. All other rate class changes are under 10%.

Board Findings

In accordance with the Board's findings with respect to Cost Allocation, the Board accepts SLHI proposal to R/C ratio of 83.08% for the SL class, yet mitigate the rate impact by transitioning to 83.08% over a two-year period. In addition, the Board accepts SLHI proposal to move the USL class to 81.30% without any rate mitigation given the dollar impact.

Deferral and Variance Accounts

Disposition of Group 1 and Group 2 Accounts

SLHI proposed to dispose of Group 1 and Group 2 deferral and variance account balances, as at December 31, 2011 and associated carrying charges forecast to April 30, 2013, as reflected in the table below. SLHI proposed to return a total credit balance amount of ($292,752) for Group 1 and Group 2 DVAs to ratepayers over a 1-year period.

		Closing Principal Balances as of Dec 31-11[2] Adjusted for Dispositions during 2012	Closing Interest Balances as of Dec 31-11 Adjusted for Dispositions during 2012	Projected Interest from Jan 1, 2012 to December 31, 2012 [1]	Projected Interest from January 1, 2013 to April 30, 2013[1]	Total Claim
Group 1 Accounts						
LV Variance Account	1550	15,524	1,393	228	76	17,221
RSVA - Wholesale Market Service Charge	1580	- 82,620	- 201	- 1,215	- 405	- 84,441
RSVA - Retail Transmission Network Charge	1584	1,331	398	20	7	1,755
RSVA - Retail Transmission Connection Charge	1586	- 15,737	94	- 231	- 77	- 15,952
RSVA - Power (excluding Global Adjustment)	1588	40,127	1,129	590	197	42,042
RSVA - Power - Sub-account - Global Adjustment	1588	- 69,209	1,659	- 1,017	- 339	- 68,906
Disposition and Recovery/Refund of Regulatory Balances (2008)	1595	- 44,366	- 2,250	- 652	- 217	- 47,485
Disposition and Recovery/Refund of Regulatory Balances (2010)	1595	- 213,808	64,832	- 3,143	- 1,048	- 153,167
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		**- 368,757**	**67,053**	**- 5,421**	**- 1,807**	**- 308,932**
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		**- 299,548**	**65,394**	**- 4,403**	**- 1,468**	**- 240,026**
RSVA - Power - Sub-account - Global Adjustment	**1588**	**- 69,209**	**1,659**	**- 1,017**	**- 339**	**- 68,906**
Group 2 Accounts						
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	17,500	-	257	86	17,843
Retail Cost Variance Account - Retail	1518	4,360	1,030	64	21	5,475
Retail Cost Variance Account - STR	1548	7,341	823	108	36	8,307
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	- 15,139	- 71	- 147	- 89	- 15,445
Group 2 Sub-Total		**14,062**	**1,782**	**282**	**54**	**16,180**
Total of Group 1 and Group 2 Accounts		- 354,695	68,835	- 5,138	- 1,753	- 292,752
[1] Carrying charges calculated on Dec 31 -11 principal balances that were adjusted for dispositions during 2012						
[2] Closing Principal Balances as of Apr 30-13 for Account 1592						

Board staff took no issue with SLHI's proposed disposition of Group 1 and Group 2 deferral and variance balances, billing determinants and rate riders subject to its submissions with respect to Account 1508. Board staff and VECC both noted there could be changes to account balances since the table was prepared. SLHI indicated it would provide an updated EDDVAR Continuity Schedule as part of the draft Rate Order once the Board issued its Decision.

<u>Board Findings</u>

The Board approves the Group 1 and Group 2 principal account balances up to December 31, 2011, subject to the Board's findings regarding Account 1508 and Account 1592. The Board directs SLHI to file the projected carrying charges up to August 31, 2013 in its draft Rate Order as SLHI's customers should not be disadvantaged by the rate impact of SLHI's late filing. Pending final calculations, the Board approves disposition of the associated credit balances over a 12-month period from September 1, 2013 to August 31, 2014.

Account 1508

SLHI proposed to dispose of Account 1508, Other Regulatory Assets, sub-account Deferred IFRS Transition Costs balance as at December 31, 2011 of $17,843.

Board staff and VECC did not support the disposition of Account 1508 in 2013. Parties submitted SLHI should request disposition in the cost of service proceeding after its IFRS transition is complete, as contemplated in the Accounting Procedures Handbook FAQ #2. Board staff suggested the Board could dispose of the December 31, 2011 balance on an interim basis and any incremental balance in SLHI's next rates proceeding.

<u>Board Findings</u>

The Board will not approve the disposal of Account 1508 at this time, either on a final or interim basis. The Board finds it more appropriate to consider this account in total after the transition to IFRS is complete as described in the Accounting Procedures Handbook.

Account 1592

In its application, SLHI proposed disposition of its December 31, 2011 balance in Account 1592, sub-account HST/OVAT ITCs. In response to a Board staff interrogatory, SLHI updated the principle balance to a ($15,139) credit as at April 30, 2013.

Board Finding

The Board directs SLHI to forecast the principle balance and associated carrying charges for Account 1592 to August 31, 2013 as part of its draft Rate Order. By determining and clearing the forecast balance when current rates are updated, there will be no residual balance in this sub account to clear in a future proceeding.

Account 1576

SLHI changed its capitalization and depreciation expense policies in 2012 under CGAAP and filed a request to clear Account 1576 "Accounting Changes under CGAAP". SLHI identified a credit balance of ($97,185) and proposed amortization over 4 years as a reduction to Depreciation Expense, consistent with previous Board policy related to accounting changes for capitalization a depreciation expenses.

Board staff submitted the credit balance and proposed disposition method were appropriate. Board staff invited SLHI to comment on the applicability of the Board's June 25, 2013 accounting policy that includes a return component on the balance of Account 1576 and uses a separate rate rider for Account disposition.

VECC submitted SLHI should include a return component on the principle amount. VECC noted that if the balance in Account 1576 had been booked in Account 1575, the balance would have included an amount based on the weighted cost of capital in accordance with Board rules. VECC submitted there is no principled difference between the use of Account 1575 or Account 1576 as both methodologies are designed to make ratepayers whole from adopting IFRS or the "IFRS like" adjustments to depreciation rates.

In reply, SLHI submitted it would not be appropriate to apply a return component and adopt a rate rider approach to Account 1576 at this time. The Board clearly indicated the policy changes will be effective for 2014 cost of service filers who have different options under the Renewed Regulatory Framework for Electricity than 2013 filers.

Board Findings

The Board agrees with SLHI that applying a return component and adopting a rate rider approach to Account 1576 would not be appropriate at this time. The Board approves SLHI's proposed 4-year amortization period as a reduction to Depreciation Expense.

Stranded Meters

SLHI proposed recovery of $181,592 in stranded meter costs over a two-year period with stranded meter rate riders ("SMRRs") of $2.83/month for Residential customers and $2.63/month for GS < 50 kW customers. In response to interrogatory 9-Staff-27d, SLHI calculated revised SMRRs of $2.74/month for Residential customers and $3.24/month for GS < 50 kW customers.

VECC supported SLHI's SMRR calculations in 9-Staff-27d as better representing meter cost causality. Board staff submitted the class-specific SMRRs in 9-Staff-27d are not in conformance with Guideline G-2011-0001. Board staff submitted the net book value of the stranded assets could be approximated on a customer class level based on available information from previous cost allocation studies. Board staff noted a calculation based on conventional meter costs rather than smart meter costs is preferable and approved by the Board in a number of cost of service decisions and accepted in Settlement Agreements.

In reply submission, SLHI calculated SMRRs of $2.80/month for Residential customers and $2.83/month for GS < 50 kW customers based on the submissions of Board Staff. SLHI had no concerns with the revised SMRR with a recovery period of 2 years.

<u>Board Findings</u>
The Board finds SLHI's revised SMRRs of $2.80/month for Residential and $2.83/month for GS < 50 kW customers to be appropriate for recovery over 24 months from September 1, 2013 to August 31, 2015.

Updated RRRP, Wholesale Market Charge and Smart Metering Entity Charges

Rural or Remote Electricity Rate Protection Charge
On March 21, 2013, the Board issued a Decision with Reasons and Rate Order (EB-2013-0067) establishing that the Rural or Remote Electricity Rate Protection ("RRRP") used by rate regulated distributors to bill their customers shall be $0.0012 per kilowatt hour effective May 1, 2013. The proposed Tariff of Rates and Charges to be filed as part of the draft Rate Order should reflect this RRRP rate effective September 1, 2013.

Wholesale Market Service Charge
On March 21, 2013, the Board issued a Decision with Reasons and Rate Order (EB-2013-0067) establishing that the Wholesale Market Service Charge ("WMSC") used by rate-regulated distributors to bill their customers shall be $0.0044 per kilowatt hour effective May 1, 2013. The proposed Tariff of Rates and Charges to be filed as part of the draft Rate Order should reflect this WMSC rate effective September 1, 2013.

Smart Meter Entity Charge
On March 28, 2013, the Board issued a Decision and Order (EB-2012-0100/EB-2012-0211) establishing a Smart Metering Entity charge of $0.79 per month for Residential and General Service < 50kW customers for those distributors identified in the Board's annual *Yearbook of Electricity Distributors* effective May 1, 2013. The draft Tariff of Rates and Charges flowing from this Decision and Order should reflect the addition of this Smart Metering Entity charge effective September 1, 2013.

Submission from Mr. Shields

Mr. Shields submitted SLHI had demonstrated over the last 6 years that the company had been in a profit position and contributed $2,528,603.00 to the Town. Mr. Shields referred to a proposed 15% increase in his delivery rate and concluded the rate increase was not required and should be denied by the Board.

<u>Board Findings</u>
Without appropriate discovery which allows parties to test the evidence and calculations, the Board is unable to verify the accuracy of the calculation of $2,528,603 and notes SLHI did not comment on the dollar amount in its reply submission. As a corporation under the Ontario Business Corporations Act, SLHI is entitled to the ability to earn a return on its investments.

The Board has reviewed Mr. Shields' submission and appreciates the time it takes for individual customers to intervene in a rates proceeding. The Board takes into account the concerns of all ratepayers as it strives to set just and reasonable rates, considering the broader public interest. The evidence filed by SLHI has been thoroughly tested and the Board finds that the resulting revenue requirement is just and reasonable. As a result of this cost of service application, the Board has made a number of adjustments to SLHI proposed application for rates in 2013. The resulting increase for residential customers will be lower than originally proposed by SLHI, with the calculation pending approval of the final Rate Order.

Implementation

The Board has made findings in this Decision which change the 2013 revenue requirement and therefore change the distribution rates from those proposed by SLHI. In filing its draft Rate Order, the Board expects SLHI to file detailed supporting material, including all relevant calculations showing the impact of the implementation of this Decision on its proposed revenue requirement, the allocation of the approved revenue requirement to the classes and the determination of the final rates and all approved rate riders, including bill impacts. Supporting documentation shall include, but not be limited to, the filing of a completed version of the Revenue Requirement Work Form Excel spreadsheet which can be found on the Board's website.

A Rate Order will be issued after the steps set out below are completed.

THE BOARD ORDERS THAT:

1. Sioux Lookout Hydro Ltd. shall file with the Board, and shall also forward to the Vulnerable Energy Consumers Coalition, a draft Rate Order attaching a proposed Tariff of Rates and Charges and other filings reflecting the Board's findings in this Decision and Order within **10 days** of the date of this Decision and Order.

2. The Vulnerable Energy Consumers Coalition and Board staff shall file any comments on the draft Rate Order with the Board and forward to Sioux Lookout Hydro Ltd. within **7 days** of the date that Sioux Lookout Hydro Ltd. files the draft Rate Order.

3. Sioux Lookout Hydro Ltd. shall file with the Board and forward to the Vulnerable Energy Consumers Coalition responses to any comments on its draft Rate Order within **4 days** of the date of receipt of Board staff and intervenor comments.

Cost Awards

The Board will issue a separate decision on cost awards once the following steps are completed:

1. The Vulnerable Energy Consumers Coalition shall submit its cost claims no later than **7 days** from the date of issuance of the final Rate Order.

2. Sioux Lookout Hydro Ltd. shall file with the Board and forward to the Vulnerable Energy Consumers Coalition any objections to the claimed costs within **17 days** from the date of issuance of the final Rate Order.

3. The Vulnerable Energy Consumers Coalition shall file with the Board and forward to Sioux Lookout Hydro Ltd. any responses to any objections for cost claims within **24 days** from the date of issuance of the final Rate Order.

4. Sioux Lookout Hydro Ltd. shall pay the Board's costs incidental to this proceeding upon receipt of the Board's invoice.

All filings to the Board must quote the file number, **EB-2012-0165**, be made through the Board's web portal at https://www.pes.ontarioenergyboard.ca/eservice/, and consist of two paper copies and one electronic copy in searchable / unrestricted PDF format. Filings must clearly state the sender's name, postal address and telephone number, fax number and e-mail address. Parties must use the document naming conventions and document submission standards outlined in the RESS Document Guideline found at http://www.ontarioenergyboard.ca/OEB/Industry. If the web portal is not available parties may email their documents to the address below. Those who do not have internet access are required to submit all filings on a CD in PDF format, along with two paper copies. Those who do not have computer access are required to file 7 paper copies.

All communications should be directed to the attention of the Board Secretary at the address below, and be received no later than 4:45 p.m. on the required date.
With respect to distribution lists for all electronic correspondence and materials related to this proceeding, parties must include the Case Manager, Suresh Advani at suresh.advani@ontarioenergyboard.ca and Board Counsel, Maureen Helt at maureen.helt@ontarioenergyboard.ca.

ADDRESS

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DATED at Toronto, August 22, 2013

ONTARIO ENERGY BOARD

Original Signed By

Kirsten Walli
Board Secretary

23

Ontario Energy Board
P.O. Box 2319

Commission de l'énergie de l'Ontario

EB-2013-0139

IN THE MATTER OF the *Ontario Energy Board Act, 1998,* S.O. 1998, c.15, (Schedule B);

AND IN THE MATTER OF an application by Hydro Hawkesbury Inc. for an order approving rates and other charges for the distribution of electricity to be effective January 1, 2014.

BEFORE: Ellen Fry
Presiding Member

Allison Duff
Member

DECISION AND ORDER
January 30, 2014

Hydro Hawkesbury Inc. ("Hydro Hawkesbury") has filed an application with the Ontario Energy Board ("the Board") under section 78 of the *Ontario Energy Board Act, 1998* (the "Act") seeking approval for the rates and other charges that Hydro Hawkesbury charges for electricity distribution, to be effective January 1, 2014.

The Vulnerable Energy Consumers Coalition ("VECC") was granted intervenor status. The Board granted Hydro Hawkesbury's request not to hold a settlement conference and to proceed by written hearing. VECC and Board staff filed interrogatories and written submissions. Hydro Hawkesbury filed interrogatory responses and written submissions in addition to the evidence included in its application.

Hydro Hawkesbury originally submitted a base revenue requirement of $1,633,225 to be recovered in rates effective January 1, 2014. In response to interrogatories, Hydro

Hawkesbury revised its base revenue requirement to $1,627,681. Based on this updated revenue requirement, Hydro Hawkesbury's proposed rates would recover a revenue deficiency of $280,667.

The following issues are addressed below in considering Hydro Hawkesbury's application:

- Alignment of Rate Year with Fiscal Year;
- Effective Date for Rates;
- Operating Revenue (Customer Forecast, Load Forecast and Other Distribution Revenue);
- Operating, Maintenance & Administration Expenses;
- Depreciation;
- Rate Base and Capital Expenditures (Incremental Capital Module, Working Capital Allowance and Green Energy Plan);
- Cost of Capital;
- Cost Allocation and Rate Design (Cost Allocation, Monthly Service Charges, Retail Transmission Service Rates, Low Voltage Charges, Loss Factors and Specific Service Charges);
- Deferral and Variance Accounts; and
- Implementation.

ALIGNMENT OF RATE YEAR WITH FISCAL YEAR

Hydro Hawkesbury requested an alignment of its fiscal and rate years to both start on January 1, in order to reduce administrative and accounting cost burdens, improve budget planning and align rates with costs. Neither VECC nor Board staff made any submissions on this issue.

The Board approves Hydro Hawkesbury's request to align its fiscal and rate years.

EFFECTIVE DATE FOR RATES

Hydro Hawkesbury applied for rates effective January 1, 2014. In Procedural Order No. 2 and Order for Interim Rates, the Board declared Hydro Hawkesbury's current rates interim effective January 1, 2014.

VECC submitted that Hydro Hawkesbury's rates should be effective January 1, 2014 only if the regulatory process is completed in sufficient time. Board staff made no submission on this matter.

In a letter dated December 11, 2012, the Board established a target date of April 26, 2013 for applications with rates effective January 1, 2014. Hydro Hawkesbury filed its initial application on May 30, 2013 and a revised application on June 13, 2013. On June 24, 2013 the Board informed Hydro Hawkesbury that its application was incomplete. On July 24, 2013 Hydro Hawkesbury filed a revised and complete application that addressed the areas of incompleteness identified by the Board.

In light of the fact that Hydro Hawkesbury ultimately filed a complete application on July 24 rather than April 26, the Board has determined that Hydro Hawkesbury's new rates will become effective March 1, 2014.

OPERATING REVENUE

Customer Forecast

Hydro Hawkesbury forecast 6,923 customers and connections (including street lighting and sentinel lights connections) for 2014. The forecast was derived by applying the class-specific historic annual growth rate for 2013 and 2014. VECC submitted that the forecast customer counts by class for 2014 were reasonable. Board staff agreed and submitted that the customer forecast proposed by Hydro Hawkesbury was consistent with the 0.8% average annual customer growth experienced during the 2010 to 2012 period.

The Board accepts Hydro Hawkesbury's proposed customer forecast for 2014.

Load Forecast

Hydro Hawkesbury's load forecast was developed in four steps. First, Hydro Hawkesbury developed a multivariate regression model that incorporates historical load and weather data from January 2004 to December 2012. Second, Hydro Hawkesbury produced 2013 bridge year and 2014 test year weather normalized purchased energy forecasts, using 9-year heating degree days and cooling degree days as inputs. Third, Hydro Hawkesbury derived the billed load forecasts from the purchased forecast and then allocated purchases to each rate class based on its shares of the historic billing trends. Fourth, Hydro Hawkesbury adjusted the 2014 forecast to account for impact of Conservation and Demand Management ("CDM") activity.

Hydro Hawkesbury's proposed load forecast for 2014 is as follows, after incorporating changes made in response to interrogatories:

Table 1: Load Forecast

Rate Class	kWh
Residential	53,488,924
GS < 50 kW	19,235,278
GS 50 to 4,999 kW	80,703,727
Street Lighting	1,136,738
Sentinel Lights	104,646
Unmetered Scattered Load	220,649
TOTAL	**154,889,963**

VECC submitted that Hydro Hawkesbury should not have used a 10 year employment level average in its model; instead, it should have used an economic conditions variable as at the close of 2012. Hydro Hawkesbury submitted that an employment level average is more reflective of the economic uncertainty in its region, and provided figures indicating a downward trend in labour force and employment. Hydro Hawkesbury indicated that it tested a 5-year rather than a 10-year average of the economic conditions variable, but it had the effect of increasing its revenue requirement.

Board staff submitted that while the proposed load forecast increase over two years is significant, it did not have any concerns as the difference is driven mostly by weather normalization. Board staff did not express any concerns with Hydro Hawkesbury's regression model.

The Board accepts Hydro Hawkesbury's argument that its economic conditions variable is appropriate given the economic uncertainty in the region and accepts its regression model as reasonable.

Hydro Hawkesbury initially made the CDM adjustment to its load forecast on the basis of gross energy savings rather than net savings, and included 2011 and 2012 CDM savings in the adjustment. In response to an interrogatory, Hydro Hawkesbury provided a revised calculation of the CDM adjustment, using net rather than gross savings, not deducting 2011 CDM savings, and deducting 50% rather than 100% of the 2012 CDM savings.

Both VECC and Board staff submitted that using net rather than gross CDM savings is the appropriate approach, consistent with the Board's decision in EB 2012-0113 concerning Centre Wellington Hydro. Hydro Hawkesbury submitted that it is agreeable to applying the net approach, but that the net approach is not reflected in the Board's July 2013 Filing Requirements.

The Board notes that Appendix 2-I of the Board's Filing Requirements refers to the decision in the Centre Wellington case, but indicates the possibility that a utility could provide support to the Board for applying a CDM adjustment on a gross basis. The Board notes that Hydro Hawkesbury has not advanced any convincing reason to use gross rather than net CDM savings in this proceeding. Accordingly, the Board has determined that, consistent with the Centre Wellington decision, that Hydro Hawkesbury should use net CDM savings.

VECC submitted that the CDM adjustment should exclude the 2011 and 2012 CDM savings because they are already captured in the historical data used Hydro Hawkesbury to develop its load forecast model. VECC submitted there should be no adjustment for 50% of the 2012 CDM program because the Board has denied the inclusion of such an adjustment in its Sioux Lookout Hydro decision (EB-2012-0165). Board staff agreed with Hydro Hawkesbury's revised calculation of the CDM adjustment, in which 50% of the 2012 CDM savings was deducted.

The Board agrees with VECC that the savings from both the 2011 and 2012 CDM programs should be excluded from the CDM adjustment. It is clear that the savings from the 2011 CDM program and from activity in 2012 under the 2012 CDM program have been embedded in the 2012 historical data and incorporated into the regression model. Concerning Hydro Hawkesbury's 2012 CDM program, the information on the record does not indicate that there was any new activity in 2013 under the 2012 CDM program.

VECC submitted that there were two errors in Hydro Hawkesbury's load forecast calculation. First, VECC submitted that Hydro Hawkesbury should have used the 2014 forecast customer count rather than the actual 2012 customer count to determine the average use per customer to apply to the increase in customers between 2013 and 2014. The Board agrees. Second, VECC submitted that in calculating the 2014 load forecast, Hydro Hawkesbury has added the new customer forecast for 2014 but omitted to add the new customer forecast for 2013. The Board agrees. The Board requires Hydro Hawkesbury to correct these two errors in the calculations for its draft Rate Order.

Other Distribution Revenue

Hydro Hawkesbury forecast total other distribution revenue of $157,139 for 2014. During the interrogatory process, Hydro Hawkesbury confirmed that the revenues from interest and dividends that were included in the forecast for other distribution revenue included carrying charges on its Retail Settlement Variance Account ("RSVA"). VECC submitted that these carrying charges should not be included in other distribution revenue, but instead should be recorded and dealt with via the RSVA. Board staff did not make submissions on this issue.

The Board agrees with VECC, and requires Hydro Hawkesbury to make this change in the calculations for its draft Rate Order.

OPERATIONS, MAINTENANCE & ADMINISTRATION ("OM & A")

Hydro Hawkesbury's proposed 2014 OM & A of $1,126,665 represents an 11.9% increase over the actual 2012 OM & A and a 19.1% increase over the 2010 Board approved OM & A. Smart meter costs comprise 50% of the overall increase in proposed OM & A. Board staff noted that Hydro Hawkesbury's average annual OM & A increase would be 2.3% if costs associated with smart metering were excluded.

VECC submitted that if Hydro Hawkesbury's 2010 OM & A was adjusted only for customer growth, inflation and incremental responsibilities it would be expected to increase by between $60,738 and $66,191, rather than the $181,073 increase proposed by Hydro Hawkesbury. VECC submitted that there were several elements in Hydro Hawkesbury's proposed OM & A budget that could be reduced without causing "undue hardship". However VECC submitted that specific reductions in the OM & A budget should be left to the discretion of Hydro Hawkesbury's management. Board staff submitted that Hydro Hawkesbury's proposed 2014 OM & A level was reasonable.

Hydro Hawkesbury submitted that even with two new transformer stations included in its proposed 2014 OM & A budget, it would still have rates at the lowest in Ontario. It submitted that its proposed 2014 OM & A budget produced one of the lowest OM & A costs per customer, a cost lower than the 2010 level for its cohort utilities.

The Board agrees with Hydro Hawkesbury that despite the increase reflected in its proposed 2014 OM & A budget, its proposed OM & A cost per customer in 2014 would still be lower than the 2010 level for other utilities of a similar size. Taking this into consideration, the Board approves Hydro Hawkesbury's proposed 2014 OM & A of $1,126,665.

DEPRECIATION

Hydro Hawkesbury proposed a depreciation expense of $222,217 in 2014. In calculating depreciation, it proposed useful lives and asset componentization in accordance with the Board's *Depreciation Study for Electricity Distributors – Transition to International Financial Reporting Standards* (EB-2010-0178).

VECC made no submissions on the proposed amount of the depreciation expense. Board staff submitted that it had no concerns with the proposed depreciation expense.

The Board approves the proposed depreciation expense of $222,217 for 2014, subject to the Board's findings in the ICM section below.

RATE BASE AND CAPITAL EXPENDITURES

Hydro Hawkesbury proposed a rate base of $7,099,556, which would represent an 87% increase from the 2012 actual amount and a 66.6% increase from the 2010 Board approved amount. Hydro Hawkesbury stated the proposed increase was primarily due to the inclusion of capital expenditures previously approved in its 2012 Incentive Regulation Mechanism ("IRM") application (EB-2011-0273) and smart meter application (EB-2012-0198).

Hydro Hawkesbury proposed capital expenditures of $272,300 in 2014. The major capital expenditure projects include pole and conductor replacement and transformer repair and exclude expenditures related to the previously approved ICM and smart meters.

Board staff submitted that Hydro Hawkesbury's capital expenditures were relatively stable and that Hydro Hawkesbury had provided sufficient support for the capital program. VECC noted that the average non-ICM expenditure was $210,000 between 2010 and 2012, lower than the average of $278,000 between 2013 and 2014. VECC submitted that Hydro Hawkesbury had increased its spending on pole replacement, similar to other Ontario electric distribution utilities, and that its capital budget was reasonable.

The Board approves capital expenditures of $272,300 and rate base of $7,099,556 in 2014, subject to the Board's findings in the following ICM section.

ICM

Hydro Hawkesbury's 2012 Incentive Regulation Mechanism ("IRM") application (EB-2011-0273) included an ICM for two projects: replacement of a 44 kV distribution transformer at a capital cost of 712,919 (the "44 kV project") and replacement of two transformers at the 110 kV substation at a capital cost of $1,517,813 (the "110 kV project"). In its decision, the Board approved the two projects and allowed Hydro Hawkesbury to recover the associated annual revenue requirement through a rate rider to start on May 1, 2012.

As part of this application, Hydro Hawkesbury filed a Fixed Asset Continuity Schedule that included $790,136 for the 44 kV project and $1,517,813 for the 110 kV project as 2013 additions.

In interrogatory responses and a letter to the Board dated January 9, 2014, Hydro Hawkesbury clarified that the 44 kV project was in service as of May 2012 as indicated in its ICM application. However, it indicated that the actual cost of the project was $790,137, which was higher than forecast. For financial reporting purposes, Hydro Hawkesbury recorded the assets in 2013 rather than 2012, as it was too late to include the assets in its 2012 audited financial statements. Hydro Hawkesbury decided to add the actual costs and accumulated depreciation to its Fixed Asset Continuity Schedule in 2013 to maintain consistency between its audited financial statements and regulatory reporting.

Hydro Hawkesbury has indicated that the increased cost for the 44 kV project was necessary in order to build a stable foundation for the transformer given poor soil conditions. VECC did not make a submission on this matter. Board staff submitted that it had no concerns with the increased costs for the 44 kV project.

Hydro Hawkesbury's IRM application indicated the 110 kV project would be in service in 2012 and would cost $1,517,813. In this proceeding, Hydro Hawkesbury indicated that the in-service date is now expected to be March 2014 with a total forecast cost $1,547,900. Hydro Hawkesbury forecast that $1,200,000 would be spent by the end of 2013 and $347,900 would be spent in 2014. However, Hydro Hawkesbury added $1,547,900 to its Fixed Asset Continuity Schedule in 2013, with accumulated depreciation.

The Board requires that Hydro Hawkesbury's 2014 rates be calculated on a set of accurate and consistent assumptions and inputs. The Fixed Asset Continuity Schedule must reflect the year in which assets go into service and are used and useful. It is important that Hydro Hawkesbury's draft Rate Order and supporting schedules include the actual dates and dollars associated with the ICM projects in order to establish just and reasonable rates.

The Board directs Hydro Hawkesbury to update its Fixed Asset Continuity Schedule as part of its draft Rate Order, to record the actual costs in the years the 44 kV and 110 kV projects are in service, with the associated accumulated depreciation. The Board notes that the cost of the two projects should include the cost of capitalized interest during the construction phases of the projects before they are placed in service. The Board directs Hydro Hawkesbury to include the capitalization of the interest during construction using the Board's prescribed Construction Work In Progress ("CWIP") interest rates posted on the Board's website (the DEX Mid Term Corporate Bond Index Yield) in the costs of these assets, if applicable, and to update the asset values in all applicable schedules. The impact of any changes would also require the updating of the balances in the subaccounts of Account 1508 for "Incremental Capital Expense" and the associated accumulated depreciation. These accounts are discussed below in the ICM-Related Variance Sub-Account section.

Accordingly, the actual 44 kV project cost is to be recorded in 2012 with accumulated depreciation and the net book value added to the 2014 rate base as of January 1, 2014.

The forecast 110 kV project cost of $1,547,900 is to be added to the 2014 rate base using the half-year rule, as it is expected to be in service in April 2014.

The Board understands that as a result of these changes Hydro Hawkesbury's regulatory and corporate financial reporting may not align. However these changes are necessary to correctly calculate the net addition to rate base in 2014 and match the timing of ICM-related charges and expenses. The Board's findings with respect to the ICM-related deferral accounts are in the Deferral and Variance Account section of this decision.

Working Capital Allowance

Hydro Hawkesbury proposed a $2,282,270 Working Capital Allowance based on the Board's default rate of 13%.

VECC submitted that a rate of 12% would be more appropriate because Hydro Hawkesbury bills its customers on a monthly basis. VECC submitted that the Board's default rate was established when most utilities offered bi-monthly billing and that monthly billing utilities have a lower need for cash than bi-monthly utilities. VECC referred to a lead-lag study completed by London Hydro, a monthly billing utility, which indicated a lower working capital requirement close to 11%. Board staff took no issue with Hydro Hawkesbury's proposal.

Hydro Hawkesbury submitted that the 13% default rate was consistent with the Board's requirements. Hydro Hawkesbury submitted that it is often forced to borrow against its line of credit in peak months to meet its obligations to Hydro One and the IESO. Hydro Hawkesbury submitted that it would be incorrect to use an arbitrary proxy as proposed by VECC rather than evidence resulting from an actual Hydro Hawkesbury lead-lag study.

The Board accepts Hydro Hawkesbury's proposal to use a 13% working capital allowance, consistent with Board policy. The Board finds no compelling reason to depart from its default rate. The Board does not consider it appropriate to adopt the results of a lead-lag study from another utility without a thorough analysis concluding that the two utilities are comparable.

Green Energy Act Plan

Hydro Hawkesbury applied for approval of its Green Energy Act Plan ("GEA Plan"). Given the low uptake of the Feed-in Tariff ("FIT") and micro-FIT programs in its service area, Hydro Hawkesbury proposed no capital investments or OM & A expenditures in its GEA Plan and did not seek any recovery of associated costs in this application. Hydro Hawkesbury sought an exemption from the Board's filing requirement that a distributor must submit its GEA Plan to the Ontario Power Authority (the "OPA") for comment prior to filing the plan with the Board. Hydro Hawkesbury indicated that it did not consider an OPA review to be warranted.

VECC did not make any submissions on Hydro Hawkesbury's GEA Plan. Board staff submitted that Hydro Hawkesbury's GEA Plan provided a comprehensive view of the capabilities of its distribution system. However, Board staff submitted that in the absence of an OPA review, the Board has no ability to verify the information that is typically verified by the OPA. Therefore, Board staff submitted that the Board should not grant Hydro Hawkesbury an exemption and should not approve Hydro Hawkesbury's GEA Plan. In its reply submission, Hydro Hawkesbury agreed to file its GEA Plan with the OPA and to file the letter of comment from the OPA when it becomes available.

The Board directs Hydro Hawkesbury to file its GEA Plan with the OPA as soon as possible and to file a copy of the OPA's response with the Board when received.

COST OF CAPITAL

Hydro Hawkesbury's original application included the following cost of capital parameters:

Table 2: Proposed Cost of Capital Parameters

Cost of Capital Parameter	Hydro Hawkesbury's Proposal
Capital Structure	60.0% debt (composed of 56.0% long-term debt and 4.0% short-term debt) and 40.0% equity
Short-Term Debt	2.07%
Long-Term Debt	3.94%
Return on Equity (ROE)	8.98%
Weighted Average Cost of Capital	5.88%

On November 25, 2013, the Board issued a letter with the updated cost of capital parameters to be used in 2014 cost of service applications for rates effective January 1, 2014. These are summarized in the following table:

Table 3: Updated Cost of Capital Parameters

Cost of Capital Parameter	Updated Value for 2014 Cost of Service Applications for rates effective January 1, 2014
Return on Equity	9.36%
Deemed Long-term Debt Rate	4.88%
Deemed Short-term Debt Rate	2.11%

Board staff submitted that Hydro Hawkesbury should update its 2014 cost of capital calculation with the new rates, except for the cost of long-term debt. Board staff agreed with Hydro Hawkesbury's proposal to use its Infrastructure Ontario debt cost of 3.94% rather than the default long-term debt rate. VECC agreed with Board staff's submission. Hydro Hawkesbury agreed to update its cost of capital parameters as submitted by Board staff as part of its draft Rate Order.

The Board finds that it is appropriate for Hydro Hawkesbury to use the Board's deemed rate of 9.36% for equity and 2.11% for short-term debt. The Board approves a long-term debt rate of 3.94% based on Hydro Hawkesbury's actual Infrastructure Ontario debt cost. As indicated in the December 2009 *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities*, the Board's default rate for long-term debt should only be used in the absence of third-party loans. Where there are third party loans, the actual interest rates should be used.

COST ALLOCATION AND RATE DESIGN

Cost Allocation

Hydro Hawkesbury updated its cost allocation model in accordance with the Board's *Review of Electricity Distribution cost Allocation Policy EB-2010-0219*. Hydro Hawkesbury used its own weighting factors, replacing the default values used in its previous cost of service application. In addition, Hydro Hawkesbury proposed to move the revenue-to-cost ratios to 100% for all rate classes. The following table summarizes Hydro Hawkesbury's current and proposed revenue-to-cost ratios compared to the Board's target range for each customer class.

Table 4: Revenue-to-Cost Ratios

Customer Class	2010 Board Approved %	Cost Allocation Model %	Proposed 2014 %	Board Target Range %
Residential	111.0	101.8	100.0	85 – 115
GS < 50 kW	111.0	107.8	100.0	80 - 120
GS 50 to 4,999 kW	80.0	87.4	100.0	80 - 120
Street Lighting	70.0	167.7	100.0	70 - 120
Sentinel Lights	120.0	147.0	100.0	80 - 120
Unmetered Scattered Load	80.0	104.3	100.0	80 - 120

VECC submitted that Hydro Hawkesbury's cost allocation model and methodology had not improved sufficiently to justify moving its revenue to cost ratios to 100%. In particular, VECC submitted that Hydro Hawkesbury had not updated the kW values for load profiles and had allocated over 50% of the distribution plant fixed assets on the basis of demand, which was "a serious flaw". VECC submitted that Hydro Hawkesbury should simply adjust the ratios to be within the Board-approved ranges. VECC referred to the Board's findings in the Toronto Hydro 2011 rates proceeding (EB-2010-0142) and the Horizon 2011 rates proceeding (EB-2010-0131) in which the Board adjusted the revenue-to-cost ratios to be within the Board-approved ranges and did not approve adjustments to 100%. VECC proposed that the revenue-to-cost ratios for the Street Lighting and Sentinel Lighting should be reduced to the upper end of the Board's approved range, that the GS>50 ratio should be increased to maintain revenue neutrality and that the other class ratios should remain unchanged.

Board staff submitted that Hydro Hawkesbury's evidence provided a good foundation for its proposed revenue re-balancing. Board staff deferred to Hydro Hawkesbury's knowledge of its own situation and did not disagree with the proposed weighting factors. However, Board staff identified an anomaly for the Unmetered Scattered Load ("USL") class. Because the USL class has no connections to the distribution system, no service costs were allocated to the USL rate class. Board staff submitted that the discrepancy was minor; however, Hydro Hawkesbury should correct the data in its cost allocation model. Hydro Hawkesbury agreed to make this change.

Board staff supported Hydro Hawkesbury's cost allocation proposal as it was designed to match revenue with the revenue requirement for each rate class. However, Board staff submitted that the proposed cost allocation changes were substantial and quite different from what the Board approved in the previous rates case. Board staff submitted that while the distribution rate increase for Residential and GS 50 to 4,999 kW was quite large, the total bill impact was attenuated or even reversed by the other components of the customer bill.

Hydro Hawkesbury submitted that its cost allocation study provided the opportunity to restore inequities and eliminate any cross subsidization that may have been in place since its last cost of service proceeding. Hydro Hawkesbury acknowledged that its load profile data may be slightly outdated, based on 2006 data, but submitted it was the best information available. Using 2006 load profile data was not a sufficient reason to leave the resulting ratios unchanged within the target range, in Hydro Hawkesbury's submission.

Hydro Hawkesbury termed its proposal an "unusually aggressive adjustment", but submitted the rate increase would not be as noticeable to customers as in other circumstances as it would be offset by a drop in the revenue requirement resulting from new capitalization policies.

The Board accepts the results of Hydro Hawkesbury's cost allocation study using utility-specific data. The results of the study indicate inequities among the rate classes in terms of cost recovery. The Board agrees that it is desirable to reduce the degree of cross subsidization, but is reluctant to move revenue-to-cost ratios to 100% for each rate class. The Board is aware that there are data limitations inherent in cost allocation models, and notes that as a practical matter, there may be little difference between a revenue-to-cost ratio of near 100% and the theoretical ideal of 100%.

The Board agrees with VECC's proposal and directs Hydro Hawkesbury to reduce the revenue-to-cost ratios for the Street Lighting and Sentinel Lighting to 120%, which is the upper end of the Board-approved range. To offset this, the Board directs Hydro Hawkesbury to increase the ratio of the GS 50 to 4,999 kW, to fully recover its costs from all rate classes.

Monthly Service Charges ("MSC")

Hydro Hawkesbury proposed to move the proportions of fixed and variable costs for all customer classes closer to 50% fixed and 50% variable (a "50/50 split"). The proposed

MSC are below the Board's ceiling rates, except for the GS 50 to 4,999 kW class. Hydro Hawkesbury's current and proposed MSC and the applicable Board ceilings are as follows:

Table 5: Current and Proposed Monthly Service Charges

Rate Class	Monthly Service Charges		
	Current	Proposed	Board Ceiling
Residential	$5.99	$10.00	$13.33
GS < 50 kW	$13.84	$15.00	$20.38
GS 50 to 4,999 kW	$97.35	$97.35	$26.50
Street Lighting	$0.62	$1.00	$1.55
Sentinel Lights	$1.63	$1.00	$2.99
Unmetered Scattered Load	$6.39	$8.50	$12.11

VECC disagreed with Hydro Hawkesbury's proposal and submitted that the current fixed/variable split should be maintained for each rate class, even though the current GS 50 to 4,999 kW MSC exceeds the Board ceiling. VECC agreed with the Hydro Hawkesbury proposal to maintain the current fixed charge of $97.35 for GS 50 to 4,999 kW for 2014 as it was consistent with Board policy to maintain the current rate even if the ceiling was exceeded. VECC noted that the Board has initiated a project (EB-2012-0410) regarding revenue decoupling for electricity distributors and submitted that the Board should not adopt Hydro Hawkesbury's proposed changes until the project is complete as it would establish a precedent.

Board staff submitted that the rationale for a 50/50 split is arbitrary and therefore should not be used as a reference point for rate design. Board staff further submitted that if Hydro Hawkesbury's proposal is approved by the Board, the proposed increase in the MSC for the Residential Class should be phased in over a 2-year period to reduce the total bill impact in 2014 below 10%. Applying this approach, the 2014 MSC for Residential customers would be $8.00.

In reply submission, Hydro Hawkesbury agreed with the Board staff recommendation to set its Residential MSC initially at $8.00 and phase in the proposed MSC of $10.00 over two years.

The Board does not find Hydro Hawkesbury's arguments compelling to justify a change in its rate design to a 50/50 split. The Board directs Hydro Hawkesbury to maintain its existing fixed/variable split for each customer class with the exception of the GS 50 to 4,999 kW class, as the monthly service charge already exceeds the ceiling.

Retail Transmission Service Rates ("RTSR")

Hydro Hawkesbury proposed RTSRs to reflect the Uniform Transmission Rates ("UTR") and the host distributor rates of Hydro One effective January 1, 2013. Electricity distributors are charged the UTRs at the wholesale level and subsequently pass these charges on to their distribution customers through the RTSRs. As a partially embedded distributor whose host is Hydro One, Hydro Hawkesbury is also charged Sub-Transmission rates by Hydro One. The proposed RTSRs are as follows:

Table 6: Proposed RTSRs

Rate Class	Hydro Hawkesbury Updated Proposal	
	RTSR Network	RTSR Connection
Residential ($/kWh)	$0.0070	$0.0032
GS < 50 kW ($/kWh)	$0.0064	$0.0028
GS 50 to 4,999 kW ($/kW)	$2.5888	$1.1437
Street Lighting ($/kW)	$1.9526	$0.8842
Sentinel Lighting ($/kW)	$1.9532	$1.8053
Unmetered Scattered Load ($/kWh)	$0.0064	$0.0028

Since the filing of Hydro Hawkesbury's application, the Board has issued its Rate Order for Hydro One Transmission (EB-2012-0031) which adjusted the UTRs effective January 1, 2014. The Board has also approved new rates for Hydro One Sub-Transmission class RTSRs effective January 1, 2014 (EB-2013-0141).

VECC submitted that Hydro Hawkesbury's revised RTSRs should be approved by the Board. Board staff submitted that Hydro Hawkesbury should update its RTSRs to reflect the new UTR's and Sub-Transmission rates.

The Board directs Hydro Hawkesbury to revise its RTSRs to incorporate the new UTRs and host distributor rates of Hydro One effective January 1, 2014, as part of its draft Rate Order. In accordance with standard practice, Variance Accounts 1584 and 1586 will continue to capture timing differences and differences in the wholesale transmission service and host distributor rates paid by Hydro Hawkesbury compared to the retail rate Hydro Hawkesbury is authorized to charge its customers.

Low Voltage Charges

Hydro Hawkesbury proposed to increase its Low Voltage ("LV") rates by 50% to 77%, depending on the class of customers, to recover its forecast LV costs of $99,595. Hydro Hawkesbury based its LV forecast on the average of its 2011 and 2012 costs and adjusted upward to reflect the projected load growth. Based on Hydro Hawkesbury's response to interrogatory 8.0-Staff-28, the average shortfall with current LV rates is $38,102 and $47,720 in those years.

Board staff submitted that Hydro Hawkesbury has justified the need for the increased LV costs in 2014 based on its actual experience in 2011 and 2012. VECC submitted that while the forecast could be refined, the cost was reasonable.

The Board approves the LV costs of $99,595 for recovery in 2014.

Loss Factors

The Distribution Loss Factor ("DLF") measures energy losses that occur within the distributor's distribution system by comparing the wholesale energy with the retail energy delivered by distributor. Similarly, the Supply Facilities Loss Factor ("SFLF") measures energy losses that occur at the point of supply, upstream of the distributor's distribution system. The Total Loss Factor ("TLF") measures the totality of these losses and is equal to the product of the DLF and SFLF. Hydro Hawkesbury applied for a TLF of 1.0541 for secondary metered customers < 5,000 kW, which is based on an underlying DLF of 1.0480 and SFLF of 1.0058. The proposed DLF and SFLF are based on the average of five historical years from 2008 to 2012. The current approved TLF for secondary metered customers < 5,000 kW is 1.0446.

VECC submitted that distribution loss factors had been declining over the last five years and it would be more appropriate for Hydro Hawkesbury to base its calculation on a three year average. VECC did not support Board staff's submission for a lower SFLF as the issue was not explored in the proceeding and there was no information on the record regarding the actual loss factors billed to Hydro Hawkesbury. As a result, VECC submitted that it was not apparent the 1.0058 proposed by Hydro Hawkesbury was inappropriate.

Board staff had no concerns with the proposed DLF, but took issue with the proposed SFLF. Board staff indicated that it appeared that Hydro Hawkesbury received approximately half of its required power through Hydro One, and that accordingly the SFLF should be adjusted to approximately to 1.02 to reflect the default SFLF for a fully embedded distributor of 1.034.

Hydro Hawkesbury maintained that its SFLF should be approved; provided more details of its 2012 SFLF; and indicated the actual percentage is 1.0055, not 1.02 as suggested by Board staff.

The Board accepts the proposed TLF of 1.0541 for secondary metered customers < 5,000 kW as submitted by Hydro Hawkesbury. The Board finds no compelling reason to accept Board staff's submission for a higher SFLF.

Specific Service Charges

Hydro Hawkesbury proposed to increase four of its specific service charges. The changes are shown in the following table.

Table 7: Existing and Proposed Specific Service Charges

Specific Service Charge	Existing Charge	Proposed Charge
Change of Occupancy	$30	$40
Disconnect/Reconnect at Meter – after regular hours	$130	$170
Install/Remove Load Control Device – after regular hours	$130	$170
Service Call – after regular hours	$130	$170

Hydro Hawkesbury provided the actual costs of providing the above services and submitted that the existing charges were not sufficient to fully recover the actual costs.

VECC agreed that the existing charges are insufficient. VECC agreed with the proposed charge of $40 for a change of occupancy, but disagreed with Hydro Hawkesbury's proposed charges for the other service rates. VECC submitted that since the actual costs related to services after regular hours were only $162.50, the charges to Disconnect/Reconnect at Meter, Install/Remove Load Control Devise and provide a Service Call should be $165 rather than $170. Board staff submitted that it had no concerns with Hydro Hawkesbury's proposal.

Hydro Hawkesbury agreed to VECC's proposed change. The Board approves Hydro Hawkesbury's revised specific service charges of $40 and $165.

DEFERRAL AND VARIANCE ACCOUNTS

Balances Proposed for Disposition

Hydro Hawkesbury is requesting disposition of the Group 1 and Group 2 deferral and variance account principal balances as at December 31, 2012 and the forecasted interest to December 31, 2013, over a one year period.

Table 8: Proposed Group 1 and 2 Account Balances for Disposition

Account #	Account Description	Disposition Amount[1]
1550	LV Variance Account	$48,843
1580	RSVA – Wholesale Market Service Charge	($116,610)
1584	RSVA – Retail Transmission Network Charge	($7,433)
1586	RSVA – Retail Transmission Connection Charge	($21,499)
1588 – Pwr	RSVA – Power (excluding Global Adjustment)	$117,602
1589 – GA	RSVA –Global Adjustment	$271,751
1595	Disposition and Recovery/Refund of Regulatory Balances (2008)	($195,709)
1508	Other Regulatory Assets – Incremental Capital Charges	$3,359
1518	Retail Cost Variance Account – Retail	$1,857
1535	Smart Grid OM&A Deferral Account	$1,901
1548	Retail Cost Variance Account – STR	$9,591
1568	LRAM Variance Account	$5,265
1576	Accounting Changes Under CGAAP Balances plus Return component	($25,155)
	Total Proposed for Disposition excluding Global Adjustment	**($177,988)**
	Total Proposed for Disposition	**$93,763**

VECC had no comments on the proposed disposition amount and period. Board staff had no concerns with Hydro Hawkesbury's updated proposed balances and disposition period.

[1] Debit amounts are recoverable from Hydro Hawkesbury's customers and credit amounts are refunded by Hydro Hawkesbury back to its customers.

BOARD FINDINGS

The Board approves the Group 1 and 2 deferral and variance accounts balances, to be disposed over a 10-month period given the implementation of rates on March 1, 2014, subject to any approved rate mitigation plan as required under Implementation, below.

Stranded Meters

Hydro Hawkesbury is requesting recovery of the net book value of $61,500 of meters removed from service when they were replaced with smart meters. Hydro Hawkesbury proposed recovery from all customer classes through stranded meter rate riders ("SMRRs"), over a two-year period. Hydro Hawkesbury requested the SMRRs shown in the table below.

Table 9: Proposed Stranded Meter Rate Riders

Rate Class	SMRR ($/month)
Residential	$0.46
GS < 50 Kw	$1.64

VECC supported Hydro Hawkesbury's proposal for recovery of stranded meter costs. Board staff made no submissions on this issue.

The Board approves the recovery of the stranded meter cost of $61,500 to be collected over a 10 month period to reflect the implementation of rates on March 1, 2014, subject to any approved rate mitigation plan as required under Implementation below.

ICM-RELATED VARIANCE SUB-ACCOUNT

Initially, Hydro Hawkesbury did not propose to dispose of the variance sub-account balances in Account 1508 related to its ICM rate rider, ICM 44 kV project costs and 110 kV project costs.

VECC submitted that Hydro Hawkesbury has clearly over collected the amount required by the current ICM rate rider as the 110 kV project was not in service in 2012 as planned. VECC was in agreement with Board staff's submission that variances in ICM riders and actual in-service amounts should be subject to reconciliation.

Board staff submitted that as the incremental revenue recovery began on May 1, 2012, a true-up calculation should take place, to reconcile the revenue recovered from ratepayers to the actual costs and in-service dates of the 44 kV and 110 kV projects. Board staff submitted that the difference should be refunded to customers by way of a rate rider.

In its reply submission, Hydro Hawkesbury agreed to true-up the difference in the revenue requirement provided it was permitted to transfer the balances from Account 1508 to Account 4080 Distribution Services Revenue. Hydro Hawkesbury requested guidance from the Board regarding the specific accounting treatment to perform the true-up.

The Board's objective is to finalize the balances in the ICM-related deferral accounts in order to dispose of the balances and close the accounts in this proceeding.

The Board directs Hydro Hawkesbury to determine the actual ICM rate rider amount collected from May 1, 2012 to February 28, 2014 associated with the 110 kV project (the "110 kV rate rider refund amount"). The Board appreciates that the rate rider balance as at December 31, 2013 is not audited and does not include amounts collected from January 1, 2014 to February 28, 2014. As a result, Hydro Hawkesbury must forecast the amount collected for two months, January and February 2014.

Once the 110 kV rate rider refund amount is determined, Hydro Hawkesbury is directed to include it in its draft Rate Order for the purpose of refunding the 110 kV rate rider refund amount to customers. The refund would occur over a 10-month period, subject to any approved rate mitigation plan as required under implementation below. In order to allow for the clearance of the rate rider collected in relation to the 44 kV project and its recognition as distribution revenue, the residual balance in Account 1508 "Incremental Capital Charge – Rate Rider" will be deemed to relate to the 44 kV project and transferred to Account 4080 Distribution Services Revenue.

In order to clear the recorded capital expenditures for the ICM projects, Hydro Hawkesbury should transfer the balances in Account 1508 "Incremental Capital Expense – Sub 110 kV Expenses" and the associated accumulated depreciation to the applicable fixed asset accounts on the completion of the project in 2014. In addition, Hydro Hawkesbury should transfer the "Incremental Capital Expense – Sub 44 kV Expenses" and the associated accumulated depreciation to the applicable fixed asset accounts as at December 31, 2013. As a result, the Board expects the balances in the three sub-accounts within Account 1508 related to the ICM projects will be cleared, resulting in zero balances and the accounts will be closed.

These accounting adjustments allow for the transfer of the approved balances from the deferral accounts to their respective operating accounts on the income statement and balance sheet.

IMPLEMENTATION

The Board has made findings in this decision which change the proposed 2014 revenue requirement and therefore change the distribution rates from those proposed by Hydro Hawkesbury. In filing its draft Rate Order, the Board expects Hydro Hawkesbury to file detailed supporting material, including all relevant calculations showing the impact of this decision on Hydro Hawkesbury's revenue requirement, the allocation of the approved revenue requirement to the classes of customer and the determination of the final rates. Supporting documentation shall include, but not be limited to, filing a completed version of the Revenue Requirement Work Form Excel spreadsheet. If as a result of these calculations the total bill increase for any customer class would exceed 10%, the Board requires Hydro Hawkesbury to file a mitigation plan as contemplated by the Board's Filing Requirements.

The Board will issue a Rate Order after the steps set out below are completed.

1. Hydro Hawkesbury shall file with the Board, and serve on VECC, a draft Rate Order attaching a proposed Tariff of Rates and Charges reflecting the Board's findings in this Decision within **14 days** of the date of the issuance of this Decision.

2. VECC and Board staff shall file any comments on the draft Rate Order with the Board and serve them on the parties within **7 days** of the date of filing of the draft Rate Order.

3. Hydro Hawkesbury shall file with the Board and serve on VECC responses to any comments on its draft Rate Order within **4 days** of the date of receipt of VECC's and Board staff's comments.

COST AWARDS

1. The Board may grant cost awards to eligible parties pursuant to its power under section 30 of the Act. In this proceeding VECC is eligible for a cost award. In determining the amount its cost award, the Board will apply the principles set out in section 5 of the Board's *Practice Direction on Cost Awards* and the maximum hourly rates set out in the Board's Cost Awards Tariff. VECC shall file with the Board and serve on Hydro Hawkesbury, its cost claim within **7 days** from the date of issuance of the final Rate Order.

2. Hydro Hawkesbury shall file with the Board and serve on VECC any objections to the claimed costs within **14 days** from the date of issuance of the final Rate Order.

3. VECC shall file with the Board and serve on Hydro Hawkesbury any responses to any objections for cost claims within **21 days** of the date of issuance of the final Rate Order.

4. Hydro Hawkesbury shall pay the Board's costs incidental to this proceeding upon receipt of the Board's invoice.

All filings with the Board must quote the file number EB-2013-0139, and be made through the Board's web portal at www.pes.ontarioenergyboard.ca/eservice/, and consist of two paper copies and one electronic copy in searchable / unrestricted PDF format. Filings must be received by the Board by 4:45 p.m. on the stated date. Parties should use the document naming conventions and document submission standards outlined in the RESS Document Guideline found at www.ontarioenergyboard.ca. If the web portal is not available, parties may e-mail their documents to the attention of the Board Secretary at BoardSec@ontarioenergyboard.ca.

DATED at Toronto, January 30, 2014

ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

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EB-2012-0113

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, (Schedule B);

AND IN THE MATTER OF an application by Centre Wellington Hydro Ltd. for an order approving just and reasonable rates and other charges for electricity distribution to be effective May 1, 2013.

BEFORE: Cynthia Chaplin
Presiding Member and Vice-Chair

Allison Duff
Member

DECISION AND ORDER
May 28, 2013

Centre Wellington Hydro Ltd. ("CWH") filed a complete application with the Ontario Energy Board on November 16, 2012 under section 78 of the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, (Schedule B), seeking approval for changes to the rates that CWH charges for electricity distribution, effective May 1, 2013. The Board issued a Notice of Application and Hearing on November 22, 2012.

CWH is an electricity distributor serving the Town of Fergus and the Village of Elora in the Township of Centre Wellington and has approximately 6,683 customers. Its application included a requested revenue requirement of $3,463,407. If the company's application were accepted in full by the Board, the impact on the bill of a typical household customer would be an increase of about $9.62 per month.

The Board conducted a written hearing. The Vulnerable Energy Consumers Coalition ("VECC") applied for and received intervenor status and cost eligibility. The hearing process included interrogatories, supplemental interrogatories, and revised evidence from the company. Board staff and VECC filed submissions on April 1 and April 4, 2013, respectively. CWH filed its reply submission on April 18, 2013.

The following issues are addressed in this Decision and Order:

- Effective Date for Rates
- Capital Expenditures and Rate Base
- Operating Revenues
- Operating Expenses
- Cost of Capital
- Cost Allocation
- Rate Design
- Deferral and Variance Accounts
- Updated RRRP, WMSC and Smart Metering Entity Charges
- Implementation

Effective Date for Rates

CWH filed its application on October 17, 2012, but the Board determined the application was incomplete. CWH completed its application on November 16, 2012.

CWH's current rates were declared interim by the Board, pending a determination in this proceeding. CWH proposed that if a final rate order was not issued before May 1, 2013, the Board should allow recovery of any foregone incremental revenue back to an effective date of May 1, 2013. Board staff and VECC took no issue with CWH's proposed effective date of May 1, 2013.

The Board will not accept the proposal to make rates effective on May 1, 2013 or allow for recovery of any foregone revenue. CWH filed its complete application in November 2012, more than two months after the Board's target date of August 31, 2012. The target date is established to allow sufficient time to complete the proceeding and issue a final rate order before May 1, 2013. In addition, the company revised its evidence regarding the accounting method used to determine rates which added a second round of interrogatories and delayed the filing of submissions. These timing issues were within the company's control. The Board therefore concludes that it would not be appropriate to make the rates effective back to May 1. CWH's new rates will be effective July 1, 2013.

Capital Expenditures and Rate Base

Capital Expenditures

CWH proposed to spend $1,876,400 on capital projects in 2013. Board staff and VECC supported this aspect of the application. The Board accepts the forecast 2013 capital expenditures.

Incremental Capital Expenditures

CWH indicated that it may apply for recovery of expenditures using the Incremental Capital Module ("ICM") in future years. The expenditures relate to the planned rehabilitation of additional municipal stations in 2014 and 2015. Board staff expressed concern with this proposal, and submitted that rebuild and rehabilitation should be supported through revenues from existing rates and that the ICM "should be relied upon strictly for non-discretionary incremental capital that cannot be funded through existing rates by prioritizing and pacing of the distributor's capital projects." VECC supported Board staff's submission. CWH, in its reply submission, accepted the position taken by Board staff and VECC, but reserved the right to file for an ICM for material capital projects where existing rates would not recover the forecasted cost of the project.

The Board will not comment on the eligibility of various projects for the ICM. The Board has rendered a number of ICM decisions which provide guiding principles, should CWH consider making an ICM application in the future. VECC proposed that CWH be directed to file a comprehensive capital plan in a subsequent application for future capital expenditures. The Board will not direct CWH to file a capital plan as part of this Decision. Just as the Board will not indicate now whether or not particular expenditures qualify for ICM treatment, the Board will not specify now that a comprehensive capital plan be filed to support an ICM application. The Board has developed generic capital plan requirements as part of the Renewed Regulatory Framework for Electricity ("RRFE") implementation process that will be applicable to cost of service applications filed for 2014 rates and beyond.

Capital Contributions

CWH forecast capital contributions of $40,900 for 2013. VECC noted that CWH significantly under forecast its capital contributions in 2012 and proposed that the 2013 forecast be increased by $32,000 to reflect historical trends. CWH disagreed with VECC's proposal. In its view, an increase in contributed capital would only be justified if there were additional capital projects that would attract contributed capital. The Board will not make the capital contributions adjustment proposed by VECC. The variance in 2012 between forecast and actual occurred in one year and does not constitute a trend. The Board is also satisfied that the types of the capital projects that CWH has projected for 2013 are consistent with a lower level of contributions.

Rate Base

CWH's forecast for 2013 rate base is $11,706,804, based on CGAAP. Board staff and VECC took no issue with CWH's rate base. In reply submission, CWH sought to make an adjustment to rate base on the basis of its final 2012 audited financial statements. The Board accepts the rate base as filed and will not make an adjustment for information presented for the first time in reply argument. It is generally inappropriate in a cost of service proceeding to rely on evidence presented through submissions. Although the information arose from an audit, the material was not tested in this proceeding.

Working Capital Allowance

CWH proposed that its Working Capital Allowance ("WCA") be calculated using 13% of the sum of the cost of power and controllable expenses as it is Board's default rate for electricity distributors. Board staff took no issue with CWH's proposal to use the default 13%, but submitted that the draft rate order CWH should update the WCA to reflect the Board's Decision and incorporate the April 5, 2013 RPP and non-RPP prices. VECC submitted that because CWH bills customers on a monthly basis, the WCA should be determined using 12% instead of 13%. VECC pointed to a recent lead lag study by London Hydro, a utility which bills monthly, which resulted in a level of 11.4%. In addition, VECC referenced a number of settlement agreements in which the parties settled on 12%. CWH opposed VECC's proposal to use 12%.

The Board accepts CWH's proposal to use 13% as it is consistent with Board policy and there is no compelling reason to depart from that policy. VECC has proposed 12% on the basis of a lead-lag study for another utility and on the basis of several settlement agreements. In accepting settlement agreements, the Board has made it clear that there is no precedential value in the individual components of a settlement agreement. The Board recognizes that all settlements contain trade-offs. The Board is also reluctant to adopt the results of a lead-lag study from one utility to another without a thorough analysis of the circumstances for each utility. CWH shall update the WCA to reflect the Board's findings in this Decision and to reflect the April 5, 2013 commodity prices.

Operating Revenues

Customer Forecast

CWH forecast the number of customers and connections by applying the geometric mean of the growth rate based on 2003-2011 actuals. The growth rates were then applied to forecast 2012 bridge and 2013 test year numbers. The customer/connection forecast was done on a class-specific basis, and the class-specific geometric mean growth rate was applied to all classes except sentinel lighting, for which customer connections were held constant. Board staff and VECC submitted that CWH's methodology was reasonable and consistent with Board policy and practice. The Board accepts the forecast of customers and connections as proposed.

Load Forecast

CWH used statistical regression to model consumption for the residential and GS<50 kW customer classes and a 3-year historical average to model normalized annual consumption ("NAC") for other customer classes, namely GS > 50 kW, Streetlighting, Unmetered Scattered Load and Sentinel Lighting.

CWH's statistical regression models were based on a number of explanatory variables to incorporate weather, employment and conservation and demand management ("CDM") data. Through the interrogatory process, CWH was asked by VECC to run other regression models and update data inputs to utilize the most current CDM results from 2011. In its reply submission, CWH agreed that it was appropriate to use the updated CDM inputs to determine the load forecast for the residential and GS<50kW classes. The Board accepts the residential and GS<50 kW load forecasts as proposed by VECC and accepted by CWH and Board staff.

CWH used a historical average use per customer to forecast growth rates for the other customer classes. Board staff accepted CWH's forecast while VECC did not. VECC submitted that the 2013 forecast should be based on the 2011 actual average annual consumption for each class. While highlighting the forecasted reduction for the USL class, VECC submitted that the 3-year negative trend in other classes was inconsistent with increasing employment and incorrectly incorporated post-2011 CDM program impacts. CWH responded that it was reasonable to expect the historical decline in demand to continue into 2013 in its service area and that the employment data related to the Kitchener-Waterloo-Barrie area included cities outside of CWH's service area.

The Board accepts CWH's demand forecast for the GS>50 KW, Intermediate, Sentinel, USL and Streetlighting customer classes. Employment data for the region does not provide sufficient basis to increase the load forecast for these classes. Other factors undoubtedly also influence the load level. Although the most recent year's data is an important consideration, there is no compelling reason to ignore results from the prior years. The Board concludes that CWH's approach provides a reasonable basis for forecasting load for these classes.

The CDM Adjustment to the Load Forecast

An adjustment for new CDM program impacts is made to the load forecast. A related amount is identified for purposes of operating the lost revenue adjustment mechanism ("LRAMVA"). CWH identified the amount of CDM savings for programs in 2011, 2012 and 2013. The data was reported by the OPA and provided on a normalized, net basis.

The company proposed that the load forecast be adjusted by 1,730,946 kWh to account for new CDM programs. Board staff and VECC did not agree with the proposed load forecast adjustments. The first year impact for CDM programs was disputed. Also, there was disagreement as to whether the adjustment should be made on a "net" or "gross" basis.

Board staff noted that CDM activities do not start on January 1^{st} and do not generate a full 12 months of CDM results in the first year. Board staff submitted that in the absence of specific information regarding program timing, the first year of each CDM program should be adjusted using the "half-year rule". VECC agreed with Board staff. CWH responded that the half-year rule was not appropriate as it appeared to be treating the CDM programs like capital assets in that asset acquisitions are allowed 50% of the depreciation expense in the year of installation. To counter the half-year recommendation, CWH included a table that estimated the 2013 monthly impact of CDM programs persisting from previous years plus the change resulting from the 2013 programs.

The Board concludes that it is appropriate to reduce the first year CDM estimates as provided by the OPA for the 2012 and 2013 programs. Program results build over the year and are not fully realized from day one. Using the half-year approach recognizes the accumulation of impacts over the year and is consistent with other Board decisions. The Board places no weight on the monthly CDM table provided by CWH in its reply submission. As indicated above, it is generally inappropriate in a cost of service proceeding to submit evidence through submissions.

With respect to the “net” and “gross” issue, Board staff agreed with CWH that the 2012 and 2013 CDM forecasts should be adjusted on a gross basis, in other words to include the CDM impact of “free riders”. Board staff noted that recent settlement agreements for other electricity distributors were based on net results, not gross, but submitted that the net CDM numbers understate the real decline in demand: “While the utility is not compensated for free ridership through the LRAMVA, the CDM savings (i.e. reduced consumption) of free riders occur in reality and will reduce consumption.” VECC submitted that the CDM adjustment should be based on the assumed net savings from the 2012 and 2013 CDM programs and not the estimated gross saving as advocated by CWH and Board staff. VECC argued that the net to gross difference does not represent additional CDM that will actually occur. VECC maintained that the individual customer class load forecasts already reflect the trends associated with natural conservation activities, activities that would have occurred without the benefit of CDM programs or incentives.

The Board agrees with VECC that the CDM savings associated with free riders and natural conservation is embedded in the historical demand data and incorporated into the demand forecast produced by the statistical regression model. The Board finds merit in VECC’s submission that “natural conservation is independent of the level of CDM programming and, therefore, future levels cannot be linked to the level of CDM programming”. The Board does not accept that the incremental 2012 and 2013 CDM programs will cause or be correlated with natural conservation savings over and above that already captured in the regression analysis. As a result, the Board will not accept the adjustment to the OPA’s CDM program estimates by a net-to-gross factor. The CDM adjustment to the load forecast is 986,133 KWh, reflecting the full year persistence of 2012 CDM programs and the initial year impact of 2013 CDM programs on 2013 load. CWH is directed to reflect this adjustment in the load forecast used for the determination and allocation of the revenue requirement, and in the determination of the rates and rate riders in its draft Rate Order filing.

The LRAMVA

A CDM impact adjustment is also identified for purposes of operating the lost revenue adjustment mechanism (“LRAMVA”). CWH identified the amount of CDM savings for programs in 2011, 2012 and 2013, and the corresponding amount used to derive the balance for the LRAMVA. The company proposed that the LRAMVA be determined using annualized “net” CDM savings of 2,288,799 kWh. Board staff and VECC supported this proposal. The Board accepts CWH’s proposal for the amount, and the allocation to customer classes on a kWh and kW basis, to be used for the determination of the LRAMVA for 2013 and 2014.

Other Revenues

CWH forecast Other Operating Revenues of $240,938 for 2013. Board staff submitted that CWH had adequately explained and supported its proposal. VECC submitted that CWH’s forecast should be increased by $20,000. In particular, VECC submitted that CWH should remove the $9,362 loss on the disposal of distribution assets as the loss will not occur under CGAAP. VECC argued that revenue offsets be increased by $9,500 as actual 2012 revenue offsets were higher than forecast. VECC also submitted that CWH had failed to forecast MicroFIT revenues of $1,400.

CWH agreed with VECC regarding the addition of the MicroFIT revenues and the removal of the $9,362 loss. However, CWH disagreed with VECC’s proposal to increase non-utility revenue offsets, as the amounts related to water and sewer billing performed for the municipality that were already included in the revenue offsets. In reply submission, CWH indicated that its MS # 1 – Elora station will require replacement in 2014 and requested that the Board approve an accelerated depreciation expense of $35,055 over the existing depreciation expense of $3,790.

The Board approves CWH’s Other Operating Revenue forecast with the addition of the MicroFITt revenues and the removal of the loss on disposal. The Board will not make any further changes for non-utility offsets. In addition, the Board will not allow for an accelerated depreciation expense for the MS #1 – Elora station as requested by CWH in its reply submission. As indicated previously, it is generally inappropriate in a cost of service proceeding to rely on evidence presented through submissions. The Board further notes that the replacement of the Elora MS is scheduled for 2014, outside of the 2013 test year period in this application.

Operating Expenses

OM&A

CWH's forecast of operations, maintenance and administration expenses ("OM&A") is $2,250,013 for 2013. The proposed OM&A is 28.3% higher than its 2009 Board-approved OM&A. CWH's annual OM&A expenses are provided below:

Year	2009 Board approved	2009 Actual	2010 Actual	2011 Actual	2012 Bridge year forecast	2013 Test Year forecast (revised)
OM&A	$1,753,350	$1,708,477	$1,758,814	$1,976,448	$2,278,700	$2,250,013

CWH lists the drivers for the increases in OM&A as follows:

- Two new staffing positions (Systems Analyst – IT in 2011 and Financial/Regulatory Analyst in 2012) to deal with increasing work in these areas;
- Annual increases in wages, salaries and other benefits;
- Decreased meter reading costs due to automated meter reading of smart meters;
- Increase in bad debt expenses due to economic factors and changes in deposit refund policy;
- Increased regulatory expenses;
- Increased computer-related costs due to move to TOU billing;
- Increased outside services for legal, audit and consulting service, unrelated to regulatory rate-setting;
- Non-labour inflation increases estimated at Canadian CPI of 2.11% (July 2012 to October 2011);
- Change in useful lives of transportation equipment, which affects OM&A through burden rates; and
- Reduction in contracted work and re-allocation of outside crew between capital and O&M work.

Board staff took no issue with the OM&A forecast and submitted that CWH had supported the proposed increase. VECC opposed the OM&A forecast and proposed a reduction of $193,408 as an envelope reduction to OM&A. VECC derived the $193,408 reduction by constructing an "expected" OM&A level based on annual inflation of 1.9%, plus customer growth of 5.25%, minus imputed productivity savings of 0.72% and minus efficiency savings of 0.6% for CWH's assigned cohort. The resulting OM&A for 2013 period would be $363,408 lower than proposed. From this "envelope" calculation, VECC proposed an adjustment of $170,000 to recognize the cost of incremental responsibilities for smart meter operations, and labour costs for regulatory and financial positions. VECC made a number of observations regarding other expense items but did not recommend individual reductions to the OM&A expense given its envelope reduction proposal.

In its reply submission, CWH argued that it had addressed the concerns raised by VECC in responses to interrogatories, and opposed any reduction to its OM&A forecast.

The Board considers the increase in OM&A from 2009 to 2013 to be unreasonable. The average annual increase is 8%. And although its customer base has grown, CWH's OM&A cost per customer has also increased by 6.2% on an annual average basis. The evidence shows that the OM&A budgets are largely based on historical spending levels and then increased to reflect additional activities or increased costs for ongoing activities. There is scant evidence of increased efficiency in CWH's operations. The only cost reductions have come in the area of meter reading, which are the result of smart meters. And the 2013 OM&A budget would in fact be even higher but for the shift of about $160,000 to capital expenditures. The Board expects to see evidence of efficiency improvements. The Board also expects to see a bottom up budget exercise balanced with a top down review. A "top-down" review is an important component of the assessment process as it demonstrates that some level of overall restraint has been considered, and potentially brought to bear. It is CWH's responsibility to manage its cost increases over time by prioritizing initiatives and activities. The Board finds that CWH has not demonstrated a sufficient level of control of its overall budget level, including the magnitude of the increase.

The Board finds merit in VECC's "envelope approach" to deriving an increase that reflects inflation, customer growth, productivity, and efficiency improvements. The Board accepts VECC's proposal which yields an OM&A amount of $1,886,605. The Board also accepts that CWH has incremental responsibilities and increasing cost pressures that cannot be completely met through efficiency improvements in other areas. The Board will therefore allow an additional $170,000, which is the amount identified by VECC and which represents the additional of two staff for specific roles. The Board is not approving those expenditures explicitly; rather it is accepting that amount as being reasonably representative of an appropriate level of incremental cost over and above what would otherwise be an appropriate level of OM&A for 2013. The total OM&A budget will be $2,056,605 ($1,886.605 + $170,000). This results in an 2013 OM&A level which represents an average annual increase of 5% since 2009. The Board finds that this is a reasonable level of increase.

The Board's mandate is not to direct an applicant on how to manage its utility and therefore the Board will not comment on specific areas in which CWH should curtail OM&A spending. Rather the Board will leave it to the discretion of CWH to manage its activities within the spending envelope.

In response to a request from CWH, the Board confirms that the LEAP amount should be derived based on 0.12% of the approved Service Revenue Requirement. CWH shall update and document the LEAP expense in the draft Rate Order.

LRAM and LRAMVA

CWH proposed recovery of an LRAM balance of $5,997.11 and an LRAMVA balance of $15,130.95. CWH proposed to recover the amounts over a one-year period. Board staff submitted that CWH had provided all relevant rate riders by customer class, that the request was consistent with the CDM Guidelines and that the LRAMVA claim is eligible for recovery. VECC made no submission. In its reply submission, CWH stated that its total LRAM and LRAMVA amount had decreased from $21,128.06 to $10,800.85. A revised balance for the 2011 LRAMVA of $4,803.74 was discovered as part of the 2012 year-end audit.

The Board approves the disposition of the LRAM balance of $5997.11. With respect to the LRAMVA balance, the Board understands that circumstances may change and new information may come to light after the close of the evidentiary portion of the hearing. However, it is inappropriate to seek recovery of a revised amount through reply submissions. The Board has two options: to re-open the proceeding to address the new information; or reach a decision on the basis of the evidence which has been tested. Given the LRAMVA is a variance account and the balance is relatively small, the Board will not dispose of the LRAMVA balance at this time. It can be addressed in CWH's next proceeding.

Cost of Capital

CWH proposed a cost of capital of 5.99% based on a deemed capital structure of 60% debt (56% long-term debt and 4% short-term debt) and 40% equity. CWH applied the Board's cost of capital parameters updated on February 14, 2013 with the exception of a long-term capital project loan at 4.23% from a third party, resulting in a weighted average long-term debt rate of 4.14%.

Board's Cost of Capital Parameters	Rate
Return on Equity	8.98%
Deemed Short-term Debt	2.07%
Deemed Long-Term Debt	4.12%

Board staff submitted CWH's proposal conformed with Board policy and practice. The Board accepts CWH's cost of capital of 5.99%.

Cost Allocation

CWH conducted a Cost Allocation study and proposed new revenue-to-cost ("R/C") ratios for its customer classes.

Revenue-to-Cost Ratios – 2011 IRM and 2013 Proposed

Customer Class	Range (%)		2011 IRM	2013 Cost Allocation	2013 Proposed
	Low	High			
Residential	85	115	101.70	97.49	99.65
GS < 50 kW	80	120	105.30	95.56	99.00
GS 50-2999 kW	80	120	104.70	90.41	99.65
GS 3000-4999 kW	80	120	87.0	100.96	100.96
Streetlighting	70	120	70.0	305.88	120.00
Sentinel Lighting	80	120	70.0	124.72	120.00
Unmetered Scattered Load	80	120	103.70	271.84	120.00

The study produced the R/C ratios in the 2013 Cost Allocation column. CWH proposed to reduce those above the "high" target rate to 120, and distribute the difference to the other classes. Board staff took no issue with the proposed R/C ratios for all customer classes. VECC submitted the cost allocation methodology was appropriate and agreed with CWH's proposal to reduce R/C ratios to the ceiling. However, VECC submitted that any shortfall be collected by increasing the R/C ratios of the other classes to the same level.

The Board accepts CWH's proposal to move streetlighting and sentinel lighting to the top of the range (120%) and to allocate the shortfall to the remaining classes. The Board does not agree with VECC's proposal to distribute R/C shortfalls to all other classes such that all ratios for the other classes are the same. VECC provided no rationale to support why this approach would be superior to CWH's approach. In any event, the resulting range under CWH's proposal (99% to 101%) is small, so equalizing them would, in the Board's view, have a minimal impact.

Rate Design

Fixed/Variable Split

CWH proposed to retain the existing fixed/variable split for all customer classes as follows:

Customer Class	Fixed % of class revenues	Volumetric %	Volumetric Billing Determinant
Residential	62.88%	37.32%	kWh
GS < 50 kW	29.52%	70.48%	kWh
GS 50-2,999 kW	19.12%	80.88%	kW
GS 3,000-4,999 kW	8.77%	91.23%	kW
Streetlighting	57.76%	42.24%	kW
Sentinel Lighting	57.54%	42.46%	kW
USL	11.17%	88.83%	kWh

Board staff took no issue with CWH's proposal. VECC proposed to cap the monthly service charge for the GS 50-2999 kW class at the ceiling value and maintain the monthly service charge for the GS 3000-4999 kW at the approved value as the ceiling value derived from the Cost Allocation Model was negative. CWH replied it would be inappropriate to make adjustments without a rate design analysis for all classes. CWH noted the Board has approved monthly service charge increases above the ceiling for other utilities. The Board accepts CWH's proposal to maintain the existing fixed/variable split in the absence of an updated rate design analysis.

MicroFIT
CWH requested an increase of the MicroFIT rate from $5.25/month to $5.40/month, in accordance with the Board's letter of September 20, 2012. No parties opposed CWH's proposal. The Board approves the MicroFIT service charge as proposed.

Low Voltage
CWH proposed Low Voltage ("LV") rates to recover $243,490.91 of LV charges from Hydro One. Board staff and VECC supported CWH's proposal. CWH increased its proposal to $332,775 in reply submission to recover additional rate riders from Hydro One. The Board will allow the recovery of $243,490.91 and will not increase the recovery amount as proposed by CWH in reply submission. As indicated previously, the Board will not base decisions on untested evidence presented for the first time in reply submission. Any difference will be captured in the LV variance account.

Retail Transmission Service Rates
CWH proposed Retail Transmission Service Rates ("RTSRs") as follows:

Customer Class	**RTSR $**	**Volumetric Billing Determinant**
Residential	0.0018	kWh
GS < 50 kW	0.0016	kWh
GS 50-2,999 kW	0.6334	kW
GS 3,000-4,999 kW	0.7471	kW
Streetlighting	0.4897	kW
Sentinel Lighting	0.5000	kW
USL	0.0016	kWh

Board staff and VECC submitted the proposed rates were appropriate. The Board accepts the RTSR as proposed.

Loss Factor
CWH used its 5-year average loss of 3.55% from 2007 to 2011 to derive its proposed total loss factor of 1.0497 for Secondary Metered customers less than 5,000 kW of demand, an increase from the current loss factor of 1.0449. Board staff and VECC supported CWH's proposal. The Board accepts the total loss factor of 1.0497 for secondary metered customers < 5,000 kW. CWH should document the corresponding total loss factor for primary metered customers < 5,000 kW in its draft Rate Order Filing.

Transformer Ownership Allowance

CWH proposed to maintain the current approved Transformer Ownership Allowance credit of $0.60/kW. No parties opposed CWH's proposal. The Board accepts CWH's proposal.

Deferral and Variance Accounts

CWH proposed a 1-year disposition period for Group 1 and Group 2 Deferral and Variance Account ("DVA") balances as at December 31, 2011. CWH requested the continuation of some of its Group 1 and Group 2 accounts, its Deferred MIFRS Transition Costs account and several new sub-accounts of Account 1595 to deal with the recovery and true-up of DVA amounts approved for disposition.

Account Description	Account Number	Total Claim ($)
LV Variance Account	1550	243,561
RSVA – Wholesale Market Service Charge	1580	(348,494)
RSVA – Retail Transmission Network Charge	1584	(156,146)
RSVA – Retail Transmission Connection Charge	1586	(116,294)
RSVA – Power (Excluding Global Adjustment)	1588	(13,987)
RSVA – Power (Global Adjustment sub-account)	1588	244,428
Recovery of Regulatory Asset Balances – Shared Taxes	1595	(4,054)
Total Group 1		**(150,987)**
Other Regulatory Assets	1508	81,797
Retail Cost Variance Account – Retail	1518	26,232
Retail Cost Variance Account – STR	1548	812
RSVA – One Time	1582	21,460
PILs and Tax Variance – Sub-Account HST/OVAT ITCs	1592	(20,017)
Total Group 2		**110,283**
Total (Group 1 and Group 2)		(40,703)

Board staff and VECC agreed with CWH's proposal except for Account 1508, sub-account Deferred IFRS Transition Costs. Accounts 1555 and 1556 for Smart Meters are discussed below. The Board accepts the proposed disposition of Group 1 and Group 2 accounts subject to the Board's decisions regarding Accounts 1508 sub-account Deferred IFRS Transition Costs, discussed below. In its draft Rate Order, CWH is directed to update the DVA Continuity Schedule to reflect the Board's finding and to calculate and propose suitable DVA rate riders taking into account the effective date of July 1, 2013 and impacts on CWH's customers.

The Board accepts CWH's request to withdraw the use and disposal of Account 1575 until it adopts IFRS.

Account 1508 – Deferred IFRS Transition Costs

CWH proposed a 1-year recovery period for the Deferred IFRS Transition Costs in Account 1508. Board staff submitted it was inappropriate to recover any IFRS transition costs until after CWH adopted IFRS, currently planned for January 1, 2015. Alternatively, Board staff suggested the Board dispose the sub-account balance of $75,704 on an interim basis, conditional on CWH completing its IFRS transition and after total transition costs were known. VECC supported Board staff's submission and suggested that, if the Board allowed disposition, it should limit recovery to 50% of the balance as the costs were not examined in this proceeding. In reply submission, CWH agreed to Board staff's suggestion to dispose of the balance on an interim basis.

The Board will not dispose of this account at this time, either on a final or interim basis. The Board finds that it is more appropriate to consider this account in total after the transition to IFRS has been made.

Accounts 1555 and 1556 - Smart Meters

CWH proposed a 4-year disposition of Accounts 1555 and 1556 related to the capital and operating costs of deploying smart meters to Residential and GS < 50 kW customers. CWH originally proposed a 2-year recovery period for both customer classes yet extended it to 4 years to ensure the total bill increase for GS < 50 kW customers did not exceed the 10% bill impact threshold.

Rate Class	Rate ($/month)	Recovery Period	Rate ($/month)	Recovery Period
Residential	$1.29	2 years	$0.57	4 years
GS < 50 kW	$8.55	2 years	$4.08	4 years

Smart meter conversion costs for GS > 50 kW customers are included in regular metering capital investments under Account 1860.

Board staff agreed with the 4-year recovery period for the GS < 50 kW class, yet suggested CWH maintain the 2-year period for Residential customers. VECC supported a 4-year recovery period for GS<50 kW customers and a 2-year period for Residential customers to match the recovery period for stranded meters. In reply submission, CWH accepted Board staff's and VECC's proposal for a 2-year recovery period for the Residential SMDR.

The Board notes that authorization to procure and deploy smart meters has been done in accordance with Government regulations, including successful participation in the London Hydro RFP process, overseen by the Fairness Commissioner, to select (a) vendor(s) for the procurement and/or installation of smart meters and related systems. There is thus a significant degree of cost control discipline that distributors, including CWH, are subject to in smart meter procurement and deployment.

The Board finds that CWH's documented costs, as revised in response to interrogatories, related to smart meter procurement, installation and operation, and including costs related to TOU rate implementation, are reasonable. As such, the Board approves the recovery of the costs applied for related to smart meter deployment and operation as of December 31, 2012, and the addition of the documented smart meter assets into the 2013 test year rate base. The Board accepts the proposed recovery of 2 years for Residential customers and 4 years for GS < 50 kW customers, adjusted to 22 and 46 months respectively to reflect the implementation of rates on July 1, 2013.

In granting its approval for the historically incurred costs and the costs projected for 2012, the Board considers CWH to have completed its smart meter deployment. Going forward, no capital and operating costs for new smart meters and the operations of smart meters shall be tracked in Accounts 1555 and 1556. Instead, costs shall be recorded in regular capital and operating expense accounts (e.g. Account 1860 for meter capital costs) as is the case with other regular distribution assets and costs.

Stranded Meters

CWH proposed a Stranded Meter Rate Rider ("SMRR") of $0.90 per month for Residential customers and $2.79 per month for GS < 50 kW customers to recover the net book value of $175,247.80 over 2 years. Board staff and VECC agreed with CWH's proposal. The Board accepts the proposed recovery of 2 years adjusted to 22 months to reflect the implementation of rates on July 1, 2013.

Updated RRRP, WMSC and Smart Metering Entity Charges

Rural or Remote Electricity Rate Protection Charge
On March 21, 2013, the Board issued a Decision with Reasons and Rate Order (EB-2013-0067) establishing that the Rural or Remote Electricity Rate Protection ("RRRP") used by rate regulated distributors to bill their customers shall be $0.0012 per kilowatt hour effective May 1, 2013. The proposed Tariff of Rates and Charges to be filed as part of the draft Rate Order should reflect this RRRP rate effective July 1, 2013.

Wholesale Market Service Charge
On March 21, 2013, the Board issued a Decision with Reasons and Rate Order (EB-2013-0067) establishing that the Wholesale Market Service Charge ("WMSC") used by rate-regulated distributors to bill their customers shall be $0.0044 per kilowatt hour effective May 1, 2013. The proposed Tariff of Rates and Charges to be filed as part of the draft Rate Order should reflect this WMSC rate effective July 1, 2013.

Smart Meter Entity Charge
On March 28, 2013, the Board issued a Decision and Order (EB-2012-0100/EB-2012-0211) establishing a Smart Metering Entity charge of $0.79 per month for Residential and General Service < 50kW customers for those distributors identified in the Board's annual *Yearbook of Electricity Distributors* effective May 1, 2013. The draft Tariff of Rates and Charges flowing from this Decision and Order should reflect the addition of this Smart Metering Entity charge effective July 1, 2013.

Implementation

The Board has made findings in this Decision which change the 2013 revenue requirement and therefore change the distribution rates from those proposed by CWH. In filing its draft Rate Order, the Board expects CWH to file detailed supporting material, including all relevant calculations showing the impact of the implementation of this Decision on its proposed revenue requirement, the allocation of the approved revenue requirement to the classes and the determination of the final rates and all approved rate riders, including bill impacts. Supporting documentation shall include, but not be limited to, the filing of a completed version of the Revenue Requirement Work Form Excel spreadsheet which can be found on the Board's website.

A Rate Order will be issued after the steps set out below are completed.

THE BOARD ORDERS THAT:

1. Centre Wellington Hydro Ltd. shall file with the Board, and shall also forward to the Vulnerable Energy Consumers Coalition, a draft Rate Order attaching a proposed Tariff of Rates and Charges and other filings reflecting the Board's findings in this Decision and Order within 10 days of the date of this Decision and Order.

2. The Vulnerable Energy Consumers Coalition and Board staff shall file any comments on the draft Rate Order with the Board and forward to Centre Wellington Hydro Ltd. within 7 days of the date that Centre Wellington Hydro Ltd. files the draft Rate Order.

3. Centre Wellington Hydro Ltd. shall file with the Board and forward to the Vulnerable Energy Consumers Coalition responses to any comments on its draft Rate Order within 4 days of the date of receipt of Board staff and intervenor comments.

Cost Awards

The Board will issue a separate decision on cost awards once the following steps are completed:

1. The Vulnerable Energy Consumers Coalition shall submit its cost claims no later than **7 days** from the date of issuance of the final Rate Order.

2. Centre Wellington Hydro Ltd. shall file with the Board and forward to the Vulnerable Energy Consumers Coalition any objections to the claimed costs within **14 days** from the date of issuance of the final Rate Order.

3. The Vulnerable Energy Consumers Coalition shall file with the Board and forward to Centre Wellington Hydro Ltd. any responses to any objections for cost claims within **21 days** from the date of issuance of the final Rate Order.

4. Centre Wellington Hydro Ltd. shall pay the Board's costs incidental to this proceeding upon receipt of the Board's invoice.

All filings to the Board must quote the file number, **EB-2012-0113**, be made through the Board's web portal at https://www.pes.ontarioenergyboard.ca/eservice/, and consist of two paper copies and one electronic copy in searchable / unrestricted PDF format. Filings must clearly state the sender's name, postal address and telephone number, fax number and e-mail address. Parties must use the document naming conventions and document submission standards outlined in the RESS Document Guideline found at http://www.ontarioenergyboard.ca/OEB/Industry. If the web portal is not available parties may email their documents to the address below. Those who do not have internet access are required to submit all filings on a CD in PDF format, along with two paper copies. Those who do not have computer access are required to file 7 paper copies.

All communications should be directed to the attention of the Board Secretary at the address below, and be received no later than 4:45 p.m. on the required date.
With respect to distribution lists for all electronic correspondence and materials related to this proceeding, parties must include the Case Manager, Keith Ritchie at keith.ritchie @ontarioenergyboard.ca and Board Counsel, Maureen Helt at maureen.helt@ontarioenergyboard.ca.

ADDRESS

Ontario Energy Board
P.O. Box 2319
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Toronto ON M4P 1E4
Attention: Board Secretary

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Tel: 1-888-632-6273 (Toll free)
Fax: 416-440-7656

DATED at Toronto, May 28, 2013

ONTARIO ENERGY BOARD

Original Signed By

Kirsten Walli
Board Secretary

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EB-2013-0130

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, (Schedule B);

AND IN THE MATTER OF an application by Fort Frances Power Corporation for an order approving just and reasonable rates and other charges for electricity distribution to be effective May 1, 2014.

BEFORE: Cathy Spoel
Presiding Member

Marika Hare
Member

DECISION AND ORDER

August 14, 2014

Fort Frances Power Corporation ("FFPC") filed a complete cost of service application with the Ontario Energy Board (the "Board") on February 14, 2014 under section 78 of the *Ontario Energy Board Act*, *1998*, S.O. 1998, c. 15, (Schedule B), seeking approval for changes to the rates that FFPC charges for electricity distribution, to be effective May 1, 2014. The Board issued a Notice of Application and Hearing dated February 25, 2014.

On March 20, 2014, the Board issued Procedural Order No. 1 and Order for Interim Rates granting requests for intervenor status and cost award eligibility to the Vulnerable Energy Consumers Coalition ("VECC") and making FFPC's current approved rates interim effective May 1, 2014 pending the outcome of this proceeding. .

The Board held a written hearing preceded by interrogatories and a non-transcribed teleconference among the parties to allow for the clarification of interrogatory responses.

The following issues are addressed below in considering FFPC's application:

- Effective Date for Rates;
- Foundational Issues
- Performance
- Operating Revenue (Customer Forecast, Load Forecast and Other Distribution Revenue);
- Operating, Maintenance & Administration Expenses;
- Depreciation;
- Rate Base and Capital Expenditures;
- Cost of Capital and Financial Performance;
- Cost Allocation and Rate Design (Cost Allocation, Monthly Service Charges and Specific Service Charges);
- Deferral and Variance Accounts; and
- Implementation.

Unless specifically addressed in this Decision and Order, the Board finds that the evidence filed by FFPC on the issues in this proceeding is sufficient to support the application.

EFFECTIVE DATE FOR RATES

FFPC applied for rates effective May 1, 2014. In Procedural Order No. 1, the Board declared FFPC's current rates interim effective May 1, 2014.

Board staff submitted that an effective date of July 1, 2014 would be appropriate as a complete version of FFPC's application was not filed with the Board until February 14, 2014 which was a delay of four and a half months from the filing date of October 1, 2013. However, Board staff also noted that subsequent to the filing of the application, FFPC filed all materials by the dates set out in the Board's Procedural Orders.

VECC agreed with Board staff that based on the late filing date the requested effective date of May 1, 2014 should not be granted. VECC submitted that rates should be declared on a forward basis subsequent to the issuance of the Board's final rate order.

FFPC agreed with Board staff's submission that an effective date for rates of July 1, 2014 would be appropriate.

The Board finds that a September 1, 2014 effective and implementation date is appropriate given the delay in filing the application, the standard time required for the Board to process a cost of service application (185 days) and the timing of the Board's Decision and Order. Under these circumstances, the Board finds that the first day of the month after the issuance of the Board's final rate order, September 1, 2014, is an appropriate effective date and is consistent with a number of previous decisions.

FOUNDATIONAL ISSUES

FFPC stated that it had organized its Distribution System Plan ("DSP") according to the expected format contained within the March 28, 2013 "Chapter 5 Consolidated Distribution System Plan Filing Requirements Guide".

FFPC stated that it is dedicated to providing services in a manner that responds to customer preferences and that during the summer of 2013, it had conducted an extensive customer satisfaction survey that was instrumental in gauging satisfaction, identifying improvement opportunities and assessing future customer needs.

FFPC further stated that the feedback gathered has helped it to shape its capital expenditures, and has allowed it to devote operational resources over the planning period to aligning service offerings with the needs of its customer base.

Board staff submitted that the planning undertaken by FFPC and outlined in the Application, as clarified by interrogatory and teleconference responses, supported the appropriate management of the applicant's assets, subject to the disallowances recommended by Board staff.

Board staff further submitted that the customer engagement activities undertaken by FFPC are commensurate with the approvals requested in the Application considering that 2014 is a transitional year. Board staff also argued that FFPC should obtain more specific customer feedback on its next DSP.

VECC submitted that while it was generally supportive of the customer engagement of FFPC, it considered that there were two deficiencies: The first was that as with most other utility surveys, no effort was made to engage customers as to the cost effectiveness of the utility. The second is that FFPC did not attempt to understand its customers' preferences or interests with respect to its capital budget.

The Board finds that FFPC has appropriately addressed the foundational issues raised by the application and its customers have been adequately engaged, given that 2014 is a transitional year. The Board agrees with Board staff and VECC that FFPC's next cost of service application should be based on customer engagement activities that will provide customers with more specific information as to the costs of its proposals.

PERFORMANCE

FFPC expressed its concern that its current performance scores derived from historic RRR reported OM&A cost data are flawed, as they include costs associated with the upkeep of the 1905 Historical Power Agreement (the "Agreement"), as well as costs associated with the upkeep and operation of a High Voltage Transformer Station, which prior to 2012 was improperly classified as a Distribution Station.

FFPC concluded that a fair assessment of its performance would be based upon its costs without the Agreement and the Transformation Station Costs or, alternatively, at the Total Bill level.

FFPC submitted that it was seeking in this proceeding an order directing Board staff and FFPC to work with the Pacific Economic Group ("PEG") to ensure that the calculations that support the scorecard and efficiency ratings for FFPC are adjusted to exclude capital and OM&A costs associated with the transformer station and the administration of the Agreement.

Board staff argued that most of the concerns expressed by FFPC either relate to costs that would have been incurred in the absence of FFPC's particular circumstances, or are already taken into account by the analysis used in determining the benchmarking categories. Accordingly, Board staff submitted that it was not necessary for the Board to provide the direction requested by FFPC upon this matter.

Board staff noted that FFPC's efficiency benchmarking performance is below average, but accepted that the beneficial effects of the Agreement offset this to some extent and considered that overall FFPC's performance supports the application.

VECC submitted that FFPC's service quality indicators are demonstrative of a well maintained utility. Where FFPC's benchmarking performance is concerned, VECC argued that as noted by Board staff, the costs related to FFPC's transformation station are a relatively small part of the overall costs of the utility and notwithstanding this fact, the FFPC benchmark performance is below average for its cohort. VECC concluded that this argued for a close examination of the proposed OM&A costs.

The Board understands that there may be some confusion as to the extent that the data sets used to determine FFPC's efficiency are appropriate. The Board directs FFPC and Board staff to work together to ensure that appropriate inputs are used for future benchmarking, if they have not already done so.

OPERATING REVENUE

Customer Forecast

FFPC forecast 4,754 customers and connections (including street lighting connections) for 2014. The forecast was derived from a review of historical customer/connection data which was used to determine growth with a geometric mean approach used to determine the 2013 and 2014 forecasts.

Board staff accepted FFPC's customer forecast. VECC submitted that the forecast customer counts by class for 2014 were reasonable, except that for the Streetlighting class, VECC submitted that the actual 2013 connection count of 1,030 should be used for 2014 in place of the forecast count of 1,006.

FFPC submitted that it is not appropriate to single out one customer class for adjustment in this way and that while using the 2013 number for Streetlighting connections happens to result in an expected decrease in rates, using the 2013 numbers for other classes will result in an expected increase in rates.

The Board approves FFPC's proposed customer forecast for 2014. The Board does not accept the adjustment proposed by VECC as it is selective and also unlikely to be material.

Load Forecast

FFPC developed its load forecast by using a multifactor regression model to determine the relationship between historic load with weather data and calendar related events.

FFPC made further adjustments to the 2014 forecast to account for the impact of Conservation and Demand Management ("CDM") activity totaling 1,148,562 kWh to the 2014 test year forecast which has been broken down by rate class. This is determined as one half of the savings from 2012 programs, a full year of savings from 2013 programs and a half year of savings from 2014 programs.

FFPC's proposed load forecast for 2014 is as follows:

Table 1: Load Forecast

Rate Class	kWh
Residential	37,751,518
GS < 50 kW	13,617,679
GS 50 to 4,999 kW	26,376,324
Street Lighting	366,947
Unmetered Scattered Load	48,552
TOTAL	**78,161,019**

VECC submitted that overall FFPC's purchased power forecast model was reasonable, but that the forecast variables for 2014 will need to be adjusted to reflect any changes approved by the Board in its 2014 forecast customer count. VECC also agreed with FFPC's CDM adjustment. Board staff also accepted FFPC's load forecast as reasonable.

The Board finds that FFPC's load forecast is appropriate. The Board notes that no party opposed the load forecast.

Other Distribution Revenue

FFPC forecast total other distribution revenue of $108,033 for 2014. FFPC also proposed the removal of unused specific service charges and a revision of some existing charges to recover current business costs.

VECC noted that FFPC's actual Other Revenues for 2013 were materially higher than FFPC's forecasts for both 2013 and 2014. VECC argued that while FFPC claimed that some of the difference could be attributed to one-time events such as Non-Utility Rental, there was Non-Utility Rental Income in each of the previous four years averaging $24,184 per year, whereas the forecast for 2014 is nil. VECC made a similar argument regarding Retail Service Revenues and submitted that it would accordingly be reasonable to increase the forecast for 2014 Other Revenues by at least $10,000 resulting in an Other Revenue Forecast for 2014 of $118,033.

Board staff noted that the proposed changes in FFPC's Other Revenues were well below its materiality threshold and accepted FFPC's evidence on this matter. Board staff also accepted the request by FFPC to remove the eight specific service charges and to increase six others, although Board staff did note that the eight charges which FFPC is requesting be removed are ones that normally appear on distributor tariffs.

FFPC submitted that its forecast Other Revenue is slightly reduced for 2014 relative to 2013 actuals to reflect realistic income levels as a result of minimal anticipated street lighting related maintenance work and customer capital projects.

The Board accepts FFPC's justification for the 2014 forecast level of Other Revenue and finds that no adjustment is necessary. The Board also accepts FFPC's proposed revisions to its specific service charges. The Board agrees that the reduction proposed by VECC to Other Revenue is well below FFPC's materiality threshold, as is the impact of the changes to FFPC's specific service charges.

OPERATIONS, MAINTENANCE & ADMINISTRATION ("OM&A")

FFPC's proposed 2014 OM&A of $1,657,650 represents a 3.3% increase over the actual 2012 OM&A and a 66% increase over the 2006 Board approved OM&A level.

Table 2: OM&A Expenses $

	2006 Board Approved	2011 Actuals	2012 Actuals	2013 Bridge Year	2014 Test Year
Operations	142,165	195,697	213,851	209,500	371,000
Maintenance	106,651	169,076	377,219	213,000	304,000
Billing & Collection	144,547	213,984	255,946	235,500	268,000
Community Relations	4,712	6.024	5,978	4,750	37,150
Administrative & General	603,271	717,211	751,977	763,500	677,500
Total	1,001,346	1,301,992	1,604,971	1,426,250	1,657,650
% Change		30.02	23.27	-11.14	16.22

VECC submitted that based on benchmarking FFPC is a high cost utility with OM&A costs per customer much higher than most Ontario electricity distributors. VECC argued that if FFPC's 2006 Board Approved OM&A were adjusted only for customer growth, inflation and incremental responsibilities it would be expected to increase by between $140,892 and $273,129, rather than the $656,304 increase proposed by FFPC. VECC submitted that while it had taken an envelope approach to its analysis, it submitted that there are areas in which OM&A savings might be achieved. VECC made a number of specific suggestions for reductions.

Board staff submitted that FFPC's proposed 2014 OM&A level should be accepted subject to a disallowance of $25,681 for proposed expenses related to the Long Term Load Transfer ("LTLT") capital project which Board staff submitted should not be approved by the Board. Board staff stated that while it did consider FFPC to be a high-cost utility FFPC's rate minimization strategy, characterized by a zero return on equity, has resulted in long term savings for ratepayers and, therefore Board staff is not recommending further OM&A reductions.

FFPC agreed with Board staff's proposal that the only adjustment to its 2014 OM&A should be the disallowance of the $25,681 proposed LTLT expenses.

FFPC submitted that VECC's model for determining expected OM&A costs is entirely unworkable, as VECC's proposed 2014 OM&A allowance would have been barely adequate for FFPC in 2008. FFPC noted that even with the staffing increase allowance of $150,000 supported by VECC, the level of increase in FFPC's 2014 OM&A cost would be lower than its actual OM&A costs from 2012 forward, and would be significantly less than requirements demonstrated by the industry as a whole. FFPC argued that VECC's approach also did not take into consideration FFPC's adjustment of its business needs to align with the requirements of the RRFE and was a backward-looking analysis, while FFPC's is forward looking.

The Board finds that the level of OM&A proposed by FFPC in its application is appropriate subject to any adjustments that may arise from the Board's findings in the Rate Base and Capital Expenditures section of this Decision and Order. The Board will not disallow the $25,681 of proposed expenses related to the LTLT capital project proposed by Board staff as the Board is approving the LTLT project as discussed in the Rate Base and Capital Expenditures section of this Decision and Order.

The Board agrees with FFPC that the adjustments to its OM&A proposed by VECC are unrealistic and therefore inappropriate for FFPC to undertake. The Board also agrees with Board staff that FFPC's rate minimization strategy has resulted in long term savings for ratepayers which allows for somewhat higher OM&A than might otherwise be the case.

DEPRECIATION

FFPC proposed a depreciation/amortization expense of $197,074 in 2014. FFPC stated that it had filed under Canadian Generally Accepted Accounting Principles ("CGAAP") for 2014, but had adjusted depreciation in 2012 to a Modified International Financial Reporting Standards ("MIFRS") calculation.

FFPC further stated that through its contracted services to the Town of Fort Frances, it did not use the Board depreciation policy of the “half-year” rule. FFPC stated that it realized its approach of using a full year of depreciation deviated from standard practice and would implement the half year rule methodology in 2014.

VECC and Board staff accepted FFPC’s proposed depreciation expense.

The Board accepts FFPC’s depreciation evidence and its proposed 2014 depreciation/amortization expense on the basis that FFPC will implement the half year rule methodology in 2014.

RATE BASE AND CAPITAL EXPENDITURES

FFPC proposed a rate base of $4,793,453, which would represent a 9% increase from the 2012 actual amount and a 7.5% increase from the 2006 Board approved amount. FFPC stated that the proposed increase in 2014 was primarily due to planned feeder expansions to eliminate LTLTs, new line transformers and transportation equipment.

FFPC projected capital expenditures to be in the $660 to $700 thousand range in the 2015 to 2018 period in its DSP, as is shown below:[1]

Table 3: Distribution System Plan Forecast

	Forecast Period (planned) ($000)				
	2014	**2015**	**2016**	**2017**	**2018**
Category					
System Access	422	40	20	45	12
System Renewal	254	419	504	531	361
System Service	49	142	60	58	15
General Plant	97	76	76	33	311
Total Expenditure	820	676	660	667	698

[1] EB-2013-0130 *Fort Frances Power Corporation Application Filed December 20, 2013, Exh 2/Tab3/Sch 1, p.4*

Board staff's submission noted that FFPC's capital spending averaged about $269,000 in the 2006 to 2012 period, but is forecast to average about $704,000 in the 2014 to 2018 period which is close to a three-fold increase in the forecast period compared to in recent years.

Board staff submitted that FFPC's proposed 2014 LTLT project should not be approved at the present time, but that a phased development plan for the servicing of this territory would be appropriate.

Board staff also submitted that the $95,648 requested by FFPC in the category of overhead and pad-mounted transformers should be reduced to $50,000 as FFPC should only replace transformers that have customer impacts categorized by FFPC as "Very High" or "High" in addition to those reported as "Failed" or "Not suitable for reuse", rather than also replacing those in the "Medium" and "Low" categories as proposed by FFPC. This meant that for the 2014 Test year, funding should only be provided for 7 out of the 15 transformers proposed to be replaced.

Board staff suggested that where FFPC's DSP was concerned, while it was relatively comprehensive, the next DSP would benefit from more emphasis on specific customer feedback regarding the DSP. The DSP would also benefit from an attempt to monetize the savings to be achieved in FFPC's OM&A over the five year planning period as it moves from a maintenance mode to a proactive capital rebuild mode.

VECC expressed general agreement with Board staff with respect to the capital renewal program. VECC submitted that the relatively young vintage of the utility's plant and the lack of detailed information on existing plant argue for a more conservative approach. VECC noted that Board staff had suggested reducing the Overhead & Pad-Mounted Transformer Replacement Program by about 50% for 2014. VECC agreed and submitted that it would be reasonable for FFPC to reduce its anticipated spending on the program by 50% for the entire 5 year period.

VECC also argued that FFPC's LTLT proposal should not be approved as it was neither reasonable to its customers who would be faced with an inordinate cost burden and risk, nor is it economically efficient and in the public interest.

FFPC agreed with the proposal of Board staff that 2014 capital expenditures be reduced from $820,316 to $402,929 and proposed to bring forward the issue of its LTLT project in a future application, once the Board has completed its policy review on the topic. FFPC suggested that the costs of this project could be dealt with in a future Incremental Capital Module submission as part of FFPC's annual IRM submission.

FFPC stated that it made the LTLT expansion proposal both to be in compliance with the Distribution System Code by June 30, 2014 and to be consistent with its belief that under the Agreement, all residents of the Town of Fort Frances, including the 14 residents who are currently served by Hydro One, are entitled to the benefits flowing from that Agreement.

FFPC noted that both Board staff and VECC had commented in their final submissions that FFPC's capital plan with respect to transformers might be aggressive and would benefit from more specific customer feedback. FFPC expressed its general agreement with this point and stated that it was committed to further improving its customer engagement activities. FFPC also accepted Board staff's recommended approach for pacing transformer replacements.

Where FFPC's proposed LTLT is concerned, the Board first notes that the situation described by FFPC is not a typical load transfer arrangement because these 14 customers are not billed by FFPC which is the geographic distributor, nor do they pay FFPC's distribution rates. Hydro One is the physical distributor for these customers (i.e. owns and operates the assets that connect them) and has been billing them since the time they were connected. The Board also notes that in response to a Board staff teleconference question, FFPC confirmed that these customers are in FFPC's service territory.

FFPC was asked during this proceeding why it did not install its own meters for these customers. FFPC explained that at the time the LTLT homes were electrified, its distribution system was not in close proximity to most of the homes and the legal dispute over the Agreement was not resolved until 1983, when the Supreme Court of Canada issued its decision on the Agreement confirming FFPC's perpetual right to call for delivery of the low cost power.[2] FFPC stated that it does not believe that it has ever

[2] *Supreme Court of Canada Decision ([1983] 1 SCR 171)*

had the consent from stakeholders, including Hydro One and the Board, to proceed with replacing the metering assets of Hydro One with its own.

FFPC was asked during the proceeding to quantify the annual savings for these customers were they to begin paying FFPC's distribution and commodity rates. FFPC estimated that for a residential customer consuming 1,000 kWh monthly in 2013, the savings would be close to 50% of the total bill.

Given the magnitude of these savings, the Board does not consider it necessary to await the completion of its policy review of long-term load transfers before making a decision on FFPC's LTLT proposal. The Board also notes that the policy review would not cover the unique circumstances of FFPC, given this is not a load transfer agreement per se, that no amendment is required to the service area, as based on the evidence provided by FFPC these customers are already within FFPC's service area, and due to the existence of the Agreement with respect to commodity prices. In addition the Board notes that FFPC stated that the completion of this project will unlock access to approximately 25.4% of its service territory that is not developed, while also offering considerably improved access for potential renewable generation facilities. A further benefit would be that the implementation of this project would provide an alternate supply of electricity in close proximity to the Fort Frances Airport.

The Board agrees with FFPC that all the customers in its service area should have the benefit of the Agreement and accordingly finds that this project is approved with one qualification. The Board notes that FFPC has stated that it believes it could extend its plant to only 13 of the 14 customers by the end of 2014. The financial impact for FFPC if it is unable to connect one of the 14 customers by the end of 2014 is between $30,000 and $46,446. The Board will approve funding of this project sufficient to allow for the connection of 13 customers in 2014. Accordingly, the Board will disallow $40,000 from the proposed capital budget. As part of the draft rate order process, the Board will expect FFPC to provide adjusted capital expenditure and operating expense levels to reflect this adjustment along with all necessary explanations. Given the magnitude of the LTLT project compared to the total capital expenditures of FFPC, the Board will establish a variance account to track the expenditures to be reviewed in a future application. FFPC shall file a draft accounting order in its draft rate order to reflect this finding.

The Board considers that overall FFPC's proposed DSP may be somewhat aggressive and finds Board staff's recommended approach for pacing transformer investments is reasonable. The Board will accordingly approve $50,000 of 2014 capital expenditures for transformers.

The Board therefore finds that it will reduce FFPC's 2014 capital expenditures request from $820,316 to an approved level of $734,668.

Capital Contributions

VECC submitted that as FFPC was using a 'net' form of capital expenditure accounting it had not properly accounted for capital contributions.

The Board notes that in response to a Board staff teleconference question[3] FFPC confirmed that its treatment of capital contributions will be consistent with Article 430 of the *Accounting Procedures Handbook* (APH").

The Board finds that FFPC's confirmation that its treatment of capital contributions will conform to the APH adequately addresses the concerns raised by VECC. FFPC should include in its draft rate order filing confirmation that the treatment of capital contributions in the 2014 Test year is in conformity with the APH.

Working Capital Allowance

FFPC proposed a $1.1 million Working Capital Allowance based on the Board's default rate of 13%.

VECC submitted that a rate of 12% would be more appropriate because FFPC bills its customers on a monthly basis. VECC submitted that the Board's default rate was established when most utilities offered bi-monthly billing and that monthly billing utilities have a lower need for cash than bi-monthly utilities. VECC referred to a lead-lag study completed by London Hydro, a monthly billing utility, which indicated a lower working capital requirement close to 11%. Board staff took no issue with FFPC's proposal.

[3] EB-2013-0130 *Fort Frances Power Corporation Response to Board Staff Teleconference on May 29, 2014 Filed on June 11, 2014*, p. 15, 4.2-Staff-43.

The Board has considered the arguments of VECC but finds no compelling reason to depart from its default rate. The Board does not consider it appropriate to adopt the results of a lead-lag study from another utility without a thorough analysis concluding that the two utilities are comparable.

Renewable Enabling Improvement ("REI") Plan

FFPC does not have any planned investments specific only to achieving smart grid objectives, but is proposing $50,000 in 2014 investments related to its development of a REI plan. This is stated by FFPC as being aimed at safely and reliably accommodating the connection of renewable energy generation facilities through improvement to its transformer station "FFMTS," which presently cannot accommodate 2-way or reverse electrical flow at any level.

FFPC is also proposing to recover $53,757 for all renewable energy generation ("REG") costs that FFPC incurred up to the end of the 2013 calendar year, including capital, OM&A and carrying charges booked in the Board established deferral accounts.

Board staff accepted FFPC's proposed REG plan as reasonable, along with the proposed allocation percentages, but expressed some concerns about the extent to which FFPC's proposed REI expenditures may also be considered as normal distribution system expenditures. Board staff argued that FFPC should provide a stronger rationalization in future applications as to how it distinguishes expenditures included in its REG plan from normal expenditures.

VECC supported the submissions of Board staff on this issue.

The Board accepts FFPC's proposals regarding its REI and REG costs as appropriate expenditures for recovery under these plans. The Board agrees with VECC and Board staff that FFPC should provide stronger rationalizations in future applications as to how it distinguishes expenditures included in its REG plan from normal expenditures.

FFPC should include in its draft rate order filing a draft accounting order for account 1533, Renewable Generation Connection Funding Adder Deferral account, "Sub-account Provincial Rate Protection Variances". In accordance with this Decision and Order, FFPC should also specify the amount that it would be expecting to receive from the IESO on a monthly and annual basis for the 2014 rate year commencing September 1, 2014.

COST OF CAPITAL AND FINANCIAL PERFORMANCE

FFPC's application included the following cost of capital parameters:

Table 4: Proposed Cost of Capital Parameters

Cost of Capital Parameter	FFPC's Proposal
Capital Structure	60.0% debt (composed of 56.0% long-term debt and 4.0% short-term debt) and 40.0% equity
Short-Term Debt	2.11%
Long-Term Debt	4.88%
Return on Equity (ROE)	0%
Weighted Average Cost of Capital	2.82%

FFPC stated that since it operates under a 0% rate-of-return, it does not have a profit margin buffer of up to 9.8% per year to absorb unforeseen expenses or the financial impact of not achieving expected efficiency gains. FFPC confirmed that it maintains a current cash investment level of $2.1 million for future capital expenditures, as a matter of policy at the direction of its Board of Directors.

Board staff submitted it would be desirable that any rate relief received by FFPC as a result of this Application be sufficient to allow it to avoid developing another accumulated deficit similar to the one that has precipitated this application during the normal 5-year period between cost of service applications.

Board staff supported FFPC's cost of capital proposal. It submitted that given FFPC's unique circumstances, including cash reserves presently exceeding $2 million, its proposed cost of capital parameters would be a sufficient buffer for FFPC in the years ahead, while resulting in considerable savings for its customers. Board staff also argued that its position is consistent with the Board's endorsement of FFPC's rate minimization strategy in 2006.

VECC submitted that nothing precluded FFPC from earning a rate of return sufficient to enable stable long-term operations. VECC argued that FFPC's proposed 0% return for rate-setting purposes was not prudent since simply based on variations in demand induced by weather a utility will over earn in some years and under earn in others. VECC submitted that while FFPC has been able to build up a considerable reserve, this is because rates recover the Board approved debt costs, while FFPC is actually debt free.

VECC submitted that it is unlikely the Agreement would be threatened by having rates calculated with the inclusion of a modest return (1-3%) since in the long run such a return would equate to zero. VECC also suggested that if FFPC was to do so under an order of the Board, it would have the added protection of a regulatory defence.

VECC argued that with respect to FFPC's long-term debt, it would be prudent for FFPC to restructure so as to have affiliated debt issued by its shareholder, through the declaration of a dividend which would then be lent back in whole or in part to FFPC. VECC pointed out that this was the common structure of municipally owned utilities in Ontario.

VECC concluded that since the overall cost of capital is significantly below the allowable amount, it supported the current cost consequences of FFPC's proposal.

The Board accepts FFPC's proposals with regard to its cost of capital as the Board is of the view that FFPC should not take any risks which could endanger the Agreement, which the Board understands is for the benefit of the residents of the Town of Fort Frances on condition power is distributed on a non-commercial basis. As noted above, the benefit to residential ratepayers who consume approximately 1000 kWh is that their total bills are approximately half of those in surrounding areas served by Hydro One. The Board does not believe that there is any reason to require FFPC to depart from its 0% rate of return policy.

COST ALLOCATION AND RATE DESIGN

Cost Allocation

FFPC stated that it has filed its application using the cost allocation model that reflects the findings in the *Report on the Review of Electricity Distribution Cost Allocation Policy,* *March 31, 2011.* ("Cost Allocation Policy Review") The following table summarizes FFPC's current and proposed revenue-to-cost ratios compared to the Board's target range for each customer class.

Table 5: Revenue-to-Cost Ratios

Customer Class	2006 Board Approved %	Cost Allocation Model %	Proposed 2014 %	Board Target Range %
Residential	91.60	83.44	97.50	85 – 115
GS < 50 kW	105.79	86.40	97.50	80 - 120
GS 50 to 4,999 kW	126.30	227.47	120.0	80 - 120
Street Lighting	89.56	94.69	97.50	70 - 120
Unmetered Scattered Load	117.05	119.68	119.31	80 - 120

VECC and Board staff accepted FFPC's cost allocation proposals as appropriate for the purposes of setting 2014 rates.

The Board finds that FFPC's proposed cost allocation is appropriate for the purpose of setting 2014 rates as all of the proposed 2014 ratios are within the Board target ranges.

Monthly Service Charges

FFPC is proposing to increase its monthly service charges as well as its volumetric charges for four of its five classes. The exception is the GS 50 to 4,999 kW class for which the fixed charge would decrease from $242.06 to $165.98 and the volumetric charge from $3.59 to $2.51.

The table below shows the current and proposed fixed charges for each class, along with the ceiling values:

Table 6: Monthly Service Charge

Rate Classes	Current	Proposed	Ceiling	Floor
Residential	$12.05	$18.79	$22.94	$9.18
GS < 50 kW	$29.03	$43.62	$33.19	$16.08
GS 50 to 4,999 kW	$242.06	$165.98	$72.00	$44.24
Street Lighting (per connection)	$1.17	$1.60	$8.93	$0.75
Unmetered Scattered Load (per customer)	$29.03	$38.24	$19.14	$7.00

VECC submitted that for a number of FFPC's customer classes, the current 2013 fixed charge is already higher than the "ceiling" as established by the cost allocation model and that for these classes, the Board should consider keeping the 2014 fixed charge at the 2013 level.

Board staff noted that the fixed charges for the GS<50kW and USL customer classes are proposed to either move further away from the ceiling or to exceed the ceiling having been below it before. In the case of the GS 50-4,999 kW class the existing monthly charge was already above the ceiling and the proposed charge moves it closer to the ceiling.

Board staff submitted that in the normal course, it would suggest to revise the fixed/variable splits in order to avoid raising the fixed charges in the GS<50 kW and USL classes. However, this would mean raising the variable component of the inter class allocation for each of these classes, one of which is a class which may continue to be impacted by the economic situation faced by the Town of Fort Frances.

Board staff accepted FFPC's decision to maintain the current fixed/variable splits at the present time noting that for typical rate class consumption levels, the total bill impacts for all rate classes are below the 10% level.

FFPC submitted that it would not be appropriate to hold the fixed charge to the 2013 level as proposed by VECC since as business closures and housing vacancies increase in the Town of Fort Frances due to the recent mill closure, the 2014 proposed fixed charge is an appropriate safeguard to protect the financial viability of FFPC.

The Board accepts FFPC's and Board staff's arguments and approves the fixed charges proposed in the application.

DEFERRAL AND VARIANCE ACCOUNTS

Balances Proposed for Disposition

FFPC is requesting disposition of the Group 1 and Group 2 deferral and variance account principal balances as at December 31, 2012 and the forecasted interest to April 30, 2014, over a two year period. FFPC stated that the default disposition term of one year would create hardship for FFPC.

Table 7: Proposed Group 1 and 2 Account Balances for Disposition

Account #	Account Description	Disposition Amount[4]
1580	RSVA – Wholesale Market Service Charge	($99,297)
1584	RSVA – Retail Transmission Network Charge	$1,588
1586	RSVA – Retail Transmission Connection Charge	($156)
1588 – Pwr	RSVA – Power (excluding Global Adjustment)	$56,077
1589 – GA	RSVA –Global Adjustment	($224,583)
1508	OEB Cost Assessment	$8,451
1508	IFRS Transition	$27,183
1531	Renewable Generation Connection	$1,966
1582	RSVA One Time	$6,891
2425	Other Deferred Credits	($6,144)
1568	LRAM Variance Account	$27,572
	Total Proposed for Disposition excluding Global Adjustment	**$24,131**
	Total Proposed for Disposition	**($200,454)**

With the exception of the balance in the LRAM Variance Account 1568 which Board staff argued should only include the LRAMVA balance of $5,050, Board staff stated that it did not have any concerns with the balances proposed for disposition. FFPC had also included an LRAM amount of $22,523 in this account relating to a period prior to the establishment of the LRAMVA which Board staff submitted it should not be recorded in the account.

[4] Debit amounts are recoverable from FFPC's customers and credit amounts are refunded by FFPC back to its customers.

FFPC confirmed in its reply submission that it would amend the LRAMVA balance in Account 1568 to $5,050, as proposed by Board staff and proposed that the LRAM amount of $22,523 would be recovered through separate rate riders.

Board staff noted that as part of the disposition request of -$200,454, FFPC had proposed disposition of its IFRS Transition Costs of $27,183 which includes forecasted interest to April 30, 2014. FFPC has also stated that it is deferring implementation of IFRS until January 1, 2015, and that costs may be incurred in the future as FFPC completes its transition to IFRS. FFPC has also requested continuation of IFRS transition costs sub-account 1508.

Board staff noted that the Board's general policy and practice is not to dispose of the Account 1508 Sub-account IFRS Transition Costs until the distributor has completed its adoption of IFRS for financial and regulatory purposes and so has a complete record of such costs to review. Board staff submitted that it did not have any issues with FFPC's proposal to dispose of the balance in Account 1508, Sub-account IFRS Transition Costs, but that it was not clear whether FFPC has any more costs booked in this account for the 2013 calendar year. Board staff recommended that FFPC identify the 2013 costs, if any, in its reply submission and if the Board was to be satisfied with the nature and quantum of these costs they could be added to the overall balance to be recovered on a final basis. FFPC confirmed in its reply submission that it did incur $12,000 in audited 2013 IFRS transition expenses which it wished to recover at this time.

VECC supported the submissions of Board staff except for the issue of disposition of Account 1508 Sub-account IFRS Transition Costs. VECC did not agree with Board staff's submission that 2013 amounts should be included in the disposition of this account. VECC submitted that FFPC should either dispose of the 2012 actuals or defer the disposition until it has completed all IFRS related spending and has a final balance for the account.

FFPC disagreed with VECC's position, submitting that it should be permitted to include the audited 2013 Account 1508 Sub-account IFRS transition costs for disposition, as it has completed the majority of the IFRS transition in 2013 and therefore, does not foresee incurring any material additional expenses related to completing the IFRS transition.

The Board accepts FFPC's proposals for disposition of the Group 1 and 2 deferral account balances. The Board agrees with Board staff that the APH should be followed, and cautions FFPC to this effect, but will accept the departures noted by FFPC in its application on the basis that the amounts involved are immaterial.

The Board will permit the disposition of the 2013 amounts in Account 1508 Sub-account IFRS Transition Costs as FFPC completed the majority of its IFRS transition in 2013 and if the balance is not disposed of now, it would be carried forward until FFPC's next cost of service application which could be in 2018 or even later.

Stranded Meters

FFPC is seeking disposition of its stranded meter costs. The net book value of the stranded conventional meters at December 31, 2013 was $80,186. FFPC proposed a one-year recovery of this amount from the Residential, GS<50 kW and GS>kW classes to align with the cost recovery approved in FFPC's EB-2012-0327 rate order. The proposed Stranded Meter Disposition Rate Riders ("SMRR") per customer are outlined in the table below:

Table 8: Proposed Stranded Meter Rate Riders

Rate Class	SMRR ($/month)
Residential	$0.86
GS < 50 kW	$6.99
GS > 50 kW	$19.63

Board staff and VECC supported FFPC's proposal for recovery of stranded meter costs.

The Board approves FFPC's proposal for the recovery of the stranded meter costs as it is aligned with the cost recovery approved in FFPC's EB-2012-0327 smart meter rate order.

CDM & LRAMVA

The Board's *Guidelines for Electricity Distributor Conservation and Demand Management* (the "CDM Guidelines") issued on April 26, 2012 outline the information that is required when filing an application for lost revenues in relation to both pre-2011 CDM activities (i.e. LRAM) and 2011-2014 CDM activities (i.e. LRAMVA). FFPC requested approval for an LRAM recovery in relation to pre-2011 CDM program savings of $22,523 arising from the recovery of lost revenues from persisting CDM savings from 2006-2010 CDM programs in 2011, 2012 and 2013.

FFPC also requested approval of an LRAMVA recovery in account 1568, specifically $5,050 in relation to energy savings from new programs deployed in 2011 and 2012 that will contribute to FFPC's 2011-2014 CDM Targets.

VECC and Board staff supported FFPC's requests.

The Board approves FFPC's requests for LRAM and LRAMVA recovery as they comply with the Board's CDM guidelines.

IMPLEMENTATION

The Board has made findings in this decision which change the proposed 2014 revenue requirement and therefore change the distribution rates from those proposed by FFPC. In filing its draft Rate Order, the Board expects FFPC to file detailed supporting material, including all relevant calculations showing the impact of this decision on FFPC's revenue requirement, the allocation of the approved revenue requirement to the classes of customer and the determination of the final rates. Supporting documentation shall include, but not be limited to, filing a completed version of the Revenue Requirement Work Form Excel spreadsheet. If as a result of these calculations the total bill increase for any customer class would exceed 10%, the Board requires FFPC to file a mitigation plan as contemplated by the Board's Filing Requirements.

THE BOARD ORDERS THAT:

1. FFPC's new distribution rates shall be effective and implemented on **September 1, 2014**.

2. FFPC shall file with the Board, and serve on VECC, a draft Rate Order attaching a proposed Tariff of Rates and Charges reflecting the Board's findings in this Decision within **14 days** of the date of the issuance of this Decision.

3. VECC and Board staff shall file any comments on the draft Rate Order with the Board and serve them on the parties within **7 days** of the date of filing of the draft Rate Order.

4. FFPC shall file with the Board and serve on VECC responses to any comments on its draft Rate Order within **4 days** of the date of receipt of VECC's and Board staff's comments.

COST AWARDS

1. The Board may grant cost awards to eligible parties pursuant to its power under section 30 of the Act. In this proceeding VECC is eligible for a cost award. In determining the amount its cost award, the Board will apply the principles set out in section 5 of the Board's *Practice Direction on Cost Awards* and the maximum hourly rates set out in the Board's Cost Awards Tariff. VECC shall file with the Board and serve on FFPC, its cost claim within **7 days** from the date of issuance of the final Rate Order.

2. FFPC shall file with the Board and serve on VECC any objections to the claimed costs within **17 days** from the date of issuance of the final Rate Order.

3. VECC shall file with the Board and serve on FFPC any responses to any objections for cost claims within **24 days** of the date of issuance of the final Rate Order.

4. FFPC shall pay the Board's costs incidental to this proceeding upon receipt of the Board's invoice.

All filings with the Board must quote the file number EB-2013-0130, and be made through the Board's web portal at www.pes.ontarioenergyboard.ca/eservice/, and consist of two paper copies and one electronic copy in searchable / unrestricted PDF format. Filings must be received by the Board by 4:45 p.m. on the stated date. Parties should use the document naming conventions and document submission standards outlined in the RESS Document Guideline found at www.ontarioenergyboard.ca. If the web portal is not available, parties may e-mail their documents to the attention of the Board Secretary at BoardSec@ontarioenergyboard.ca.

DATED at Toronto, August 14, 2014

ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

B

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Statutory Powers Procedure Act, RSO 1990, c S.22

Current version: in force since Jun 1, 2011

Link to the latest version:	http://canlii.ca/t/2qg
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Statutory Powers Procedure Act

R.S.O. 1990, CHAPTER S.22

Consolidation Period: From June 1, 2011 to the e-Laws currency date.

Last amendment: 2009, c. 33, Sched. 6, s. 87.

Interpretation

1. (1) In this Act,

"electronic hearing" means a hearing held by conference telephone or some other form of electronic technology allowing persons to hear one another; ("audience électronique")

"hearing" means a hearing in any proceeding; ("audience")

"licence" includes any permit, certificate, approval, registration or similar form of permission required by law; ("autorisation")

"municipality" has the same meaning as in the *Municipal Affairs Act*; ("municipalité")

"oral hearing" means a hearing at which the parties or their representatives attend before the tribunal in person; ("audience orale")

"proceeding" means a proceeding to which this Act applies; ("instance")

"representative" means, in respect of a proceeding to which this Act applies, a person authorized

Notice of filing

(2) A party who files an order under subsection (1) shall notify the tribunal within 10 days after the filing. 1994, c. 27, s. 56 (35).

Order for payment of money

(3) On receiving a certified copy of a tribunal's order for the payment of money, the sheriff shall enforce the order as if it were an execution issued by the Superior Court of Justice. 1994, c. 27, s. 56 (35); 2006, c. 19, Sched. C, s. 1 (1).

Record of proceeding

20. A tribunal shall compile a record of any proceeding in which a hearing has been held which shall include,

(a) any application, complaint, reference or other document, if any, by which the proceeding was commenced;

(b) the notice of any hearing;

(c) any interlocutory orders made by the tribunal;

(d) all documentary evidence filed with the tribunal, subject to any limitation expressly imposed by any other Act on the extent to or the purposes for which any such documents may be used in evidence in any proceeding;

(e) the transcript, if any, of the oral evidence given at the hearing; and

(f) the decision of the tribunal and the reasons therefor, where reasons have been given. R.S.O. 1990, c. S.22, s. 20.

Adjournments

21. A hearing may be adjourned from time to time by a tribunal of its own motion or where it is shown to the satisfaction of the tribunal that the adjournment is required to permit an adequate hearing to be held. R.S.O. 1990, c. S.22, s. 21.

Correction of errors

21.1 A tribunal may at any time correct a typographical error, error of calculation or similar error made in its decision or order. 1994, c. 27, s. 56 (36).

Power to review

21.2 (1) A tribunal may, if it considers it advisable and if its rules made under section 25.1 deal with the matter, review all or part of its own decision or order, and may confirm, vary, suspend or cancel the decision or order. 1997, c. 23, s. 13 (20).

Time for review

(2) The review shall take place within a reasonable time after the decision or order is made.

Conflict

(3) In the event of a conflict between this section and any other Act, the other Act prevails. 1994, c. 27, s. 56 (36).

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Ontario Energy Board Act, 1998, SO 1998, c 15, Sch B

Current version: in force since Jun 4, 2015

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Ontario Energy Board Act, 1998

S.O. 1998, CHAPTER 15
SCHEDULE B

Consolidation Period: From June 4, 2015 to the e-Laws currency date.

Last amendment: 2015, c. 20, Sched. 31.

PART I
GENERAL

Board objectives, electricity

1. (1) The Board, in carrying out its responsibilities under this or any other Act in relation to electricity, shall be guided by the following objectives:

1. To protect the interests of consumers with respect to prices and the adequacy, reliability and quality of electricity service.
2. To promote economic efficiency and cost effectiveness in the generation, transmission, distribution, sale and demand management of electricity and to facilitate the maintenance of a financially viable electricity industry.

3. To promote electricity conservation and demand management in a manner consistent with the policies of the Government of Ontario, including having regard to the consumer's economic circumstances.

4. To facilitate the implementation of a smart grid in Ontario.

5. To promote the use and generation of electricity from renewable energy sources in a manner consistent with the policies of the Government of Ontario, including the timely expansion or reinforcement of transmission systems and distribution systems to accommodate the connection of renewable energy generation facilities. 2004, c. 23, Sched. B, s. 1; 2009, c. 12, Sched. D, s. 1.

Facilitation of integrated power system plans

(2) In exercising its powers and performing its duties under this or any other Act in relation to electricity, the Board shall facilitate the implementation of all integrated power system plans approved under the *Electricity Act, 1998*. 2004, c. 23, Sched. B, s. 1.

Board objectives, gas

2. The Board, in carrying out its responsibilities under this or any other Act in relation to gas, shall be guided by the following objectives:

1. To facilitate competition in the sale of gas to users.

2. To protect the interests of consumers with respect to prices and the reliability and quality of gas service.

3. To facilitate rational expansion of transmission and distribution systems.

4. To facilitate rational development and safe operation of gas storage.

5. To promote energy conservation and energy efficiency in accordance with the policies of the Government of Ontario, including having regard to the consumer's economic circumstances.

5.1 To facilitate the maintenance of a financially viable gas industry for the transmission, distribution and storage of gas.

6. To promote communication within the gas industry and the education of consumers. 1998, c. 15, Sched. B, s. 2; 2002, c. 23, s. 4 (2); 2003, c. 3, s. 3; 2004, c. 23, Sched. B, s. 2; 2009, c. 12, Sched. D, s. 2.

Definitions

3. In this Act,

"affiliate", with respect to a corporation, has the same meaning as in the *Business Corporations Act*; ("membre du même groupe")

"associate", where used to indicate a relationship with any person, means,

(a) any body corporate of which the person owns, directly or indirectly, voting securities carrying more than 50 per cent of the voting rights attached to all voting securities of the body corporate for the time being outstanding,

(b) any partner of that person,

(c) any trust or estate in which the person has a substantial beneficial interest or as to which the person serves as trustee or in a similar capacity,

(d) any relative of the person, including the person's spouse as defined in the *Business Corporations Act*, where the relative has the same home as the person, or

Collection of personal information

4.14 The Board may collect personal information within the meaning of section 38 of the *Freedom of Information and Protection of Privacy Act* for the purpose of carrying out its duties and exercising its powers under this or any other Act. 2003, c. 3, s. 12.

Non-application of certain Acts

4.15 The *Corporations Act* and the *Corporations Information Act* do not apply with respect to the Board. 2003, c. 3, s. 12.

Members and employees

4.16 (1) Repealed: 2006, c. 35, Sched. C, s. 98.

Status of members

(2) The members of the Board are not its employees, and the chair and vice-chairs shall not hold any other office in the Board or be employed by it in any other capacity. 2003, c. 3, s. 12.

Conflict of interest, indemnification

(3) Sections 132 (conflict of interest) and 136 (indemnification) of the *Business Corporations Act* apply with necessary modifications with respect to the Board as if the Minister were its sole shareholder. 2003, c. 3, s. 12.

Agreement for services

(4) The Board and a ministry of the Crown may enter into agreements for the provision by employees of the Crown of any service required by the Board to carry out its duties and powers, and the Board shall pay the agreed amount for services provided to it. 2003, c. 3, s. 12.

Chief operating officer and secretary

5. The Board's management committee shall appoint a chief operating officer of the Board and a secretary of the Board from among the Board's employees. 2003, c. 3, s. 13.

Delegation of Board's powers and duties

6. (1) The Board's management committee may in writing delegate any power or duty of the Board to an employee of the Board. 2003, c. 3, s. 13.

Exceptions

(2) Subsection (1) does not apply to the following powers and duties:

1. Any power or duty of the Board's management committee.
2. The power to make rules under section 44.
3. The power to issue codes under section 70.1.
4. The power to make rules under section 25.1 of the *Statutory Powers Procedure Act*.
5. Hearing and determining an appeal under section 7 or a review under section 8.
6. The power to make an order against a person under section 112.3, 112.4 or 112.5, if the person gives notice requiring the Board to hold a hearing under section 112.2.
7. A power or duty prescribed by the regulations. 2003, c. 3, s. 13.

Conditions and restrictions

(3) A delegation under this section is subject to such conditions and restrictions as the management committee may specify in writing. 2003, c. 3, s. 13.

No hearing

(4) An employee of the Board may exercise powers and duties that are delegated under this section without holding a hearing. 2003, c. 3, s. 13.

Statutory Powers Procedure Act

(5) If an employee of the Board holds a hearing pursuant to this section, the *Statutory Powers Procedure Act* applies to the same extent as if members of the Board were holding the hearing. 2003, c. 3, s. 13.

Review by employee

(6) An employee of the Board who makes an order pursuant to this section may, within a reasonable time after the order is made and if he or she considers it advisable, review all or part of the order, and may confirm, vary or cancel the order. 2003, c. 3, s. 13.

Transfer to Board

(7) At any time before an employee of the Board makes an order in respect of a matter pursuant to this section, the management committee may direct that the matter be transferred to the Board for determination. 2003, c. 3, s. 13.

Effect of employees' orders, etc.

(8) Anything done by an employee of the Board pursuant to this section shall be deemed, for the purpose of this or any other Act, to have been done by the Board. 2003, c. 3, s. 13.

Application of s. 33

(9) Despite subsection (8), section 33 and subsection 38 (4) do not apply to an order made by an employee of the Board pursuant to this section. 2003, c. 3, s. 13; 2009, c. 33, Sched. 2, s. 51 (1).

Appeal from delegated function

7. (1) A person directly affected by an order made by an employee of the Board pursuant to section 6 may, within 15 days after receiving notice of the order, appeal the order to the Board. 2003, c. 3, s. 13.

Exception

(2) Subsection (1) does not apply to,

(a) a person who did not make submissions to the employee after being given notice of the opportunity to do so; or

(b) a person who did not give notice requiring the Board to hold a hearing under section 112.2, in the case of an order made by the employee under section 112.3, 112.4 or 112.5. 2003, c. 3, s. 13.

Parties

(3) The parties to the appeal are:

1. The appellant.
2. The applicant, if the order is made in a proceeding commenced by an application.
3. The employee who made the order.
4. Any other person added as a party by the Board. 2003, c. 3, s. 13.

Powers of Board

(4) The Board may confirm, vary or cancel the order. 2003, c. 3, s. 13.

Stay

Inclusion of Board costs

(4) The costs may include the costs of the Board, regard being had to the time and expenses of the Board. 1998, c. 15, Sched. B, s. 30 (4).

Considerations not limited

(5) In awarding costs, the Board is not limited to the considerations that govern awards of costs in any court. 1998, c. 15, Sched. B, s. 30 (5).

Application

(6) This section applies despite section 17.1 of the *Statutory Powers Procedure Act*. 2003, c. 3, s. 25 (2).

31. (1) Repealed: 2002, c. 1, Sched. B, s. 5.

(2) Repealed: 2003, c. 3, s. 26.

Stated case

32. (1) The Board may, at the request of the Lieutenant Governor in Council or of its own motion or upon the motion of any party to proceedings before the Board and upon such security being given as it directs, state a case in writing for the opinion of the Divisional Court upon any question that is a question of law within the jurisdiction of the Board. 1998, c. 15, Sched. B, s. 32 (1); 2003, c. 3, s. 27.

Same

(2) The Divisional Court shall hear and determine the stated case and remit it to the Board with its opinion. 1998, c. 15, Sched. B, s. 32 (2).

Appeal to Divisional Court

33. (1) An appeal lies to the Divisional Court from,

(a) an order of the Board;

(b) the making of a rule under section 44; or

(c) the issuance of a code under section 70.1. 2003, c. 3, s. 28 (1).

Nature of appeal, timing

(2) An appeal may be made only upon a question of law or jurisdiction and must be commenced not later than 30 days after the making of the order or rule or the issuance of the code. 1998, c. 15, Sched. B, s. 33 (2); 2003, c. 3, s. 28 (2).

Board may be heard

(3) The Board is entitled to be heard by counsel upon the argument of an appeal. 1998, c. 15, Sched. B, s. 33 (3).

Board to act on court's opinion

(4) The Divisional Court shall certify its opinion to the Board and the Board shall make an order in accordance with the opinion, but the order shall not be retroactive in its effect. 1998, c. 15, Sched. B, s. 33 (4).

Board not liable for costs

(5) The Board, or any member of the Board, is not liable for costs in connection with any appeal under this section. 1998, c. 15, Sched. B, s. 33 (5).

Order to take effect despite appeal

(6) Subject to subsection (7), every order made by the Board takes effect at the time prescribed in the order, and its operation is not stayed by an appeal, unless the Board orders otherwise. 2006, c. 33, Sched. X, s. 1.

Court may stay the order

(7) The Divisional Court may, on an appeal of an order made by the Board,

(a) stay the operation of the order; or

(b) set aside a stay of the operation of the order that was ordered by the Board under subsection (6). 2006, c. 33, Sched. X, s. 1.

No petition to Lieutenant Governor in Council

Definition

34. (1) In this section,

"old section 34" means this section as it read immediately before the day the *Good Government Act, 2009* received Royal Assent. 2009, c. 33, Sched. 2, s. 51 (2).

Not subject to petition

(2) Every order, rule or code of the Board that is the subject of a petition filed under the old section 34 that is not disposed of or withdrawn before the day the *Good Government Act, 2009* receives Royal Assent is deemed not to be subject to petition to the Lieutenant Governor in Council, and shall not be considered or continue to be considered, as the case may be, by the Lieutenant Governor in Council. 2009, c. 33, Sched. 2, s. 51 (2).

Same

(3) Every order, rule or code of the Board that may be the subject of a petition under the old section 34 is deemed not to be subject to petition to the Lieutenant Governor in Council, and shall not be considered by the Lieutenant Governor in Council. 2009, c. 33, Sched. 2, s. 51 (2).

No effect on validity

(4) Nothing in this section affects the validity of an order, rule or code of the Board that, but for subsection 51 (2) of Schedule 2 to the *Good Government Act, 2009*, was or could have been the subject of a petition filed under the old section 34. 2009, c. 33, Sched. 2, s. 51 (2).

Question referred to Board

35. The Minister may require the Board to examine, report and advise on any question respecting energy. 1998, c. 15, Sched. B, s. 35.

PART III
GAS REGULATION

Order of Board required

36. (1) No gas transmitter, gas distributor or storage company shall sell gas or charge for the transmission, distribution or storage of gas except in accordance with an order of the Board, which is not bound by the terms of any contract. 1998, c. 15, Sched. B, s. 36 (1).

Order of Board re Smart Metering Entity

(1.1) Neither the Smart Metering Entity nor any other person licensed to do so shall conduct activities relating to the metering of gas except in accordance with an order of the Board, which is not bound by the terms of any contract. 2006, c. 3, Sched. C, s. 3.

Order re: rates

Codes that may be incorporated as licence conditions

70.1 (1) The Board may issue codes that, with such modifications or exemptions as may be specified by the Board under section 70, may be incorporated by reference as conditions of a licence under that section. 2003, c. 3, s. 48.

Quorum

(2) For the purposes of this section and section 70.2, two members of the Board constitute a quorum. 2003, c. 3, s. 48.

Approval, etc., of Board

(3) A code issued under this section may provide that an approval, consent or determination of the Board is required, with or without a hearing, for any of the matters provided for in the code. 2003, c. 3, s. 48.

Incorporation of standards, etc.

(4) A code issued under this section may incorporate by reference, in whole or in part, any standard, procedure or guideline. 2003, c. 3, s. 48.

Scope

(5) A code may be general or particular in its application and may be limited as to time or place or both. 2003, c. 3, s. 48.

***Legislation Act, 2006*, Part III**

(6) Part III (Regulations) of the *Legislation Act, 2006* does not apply to a code issued under this section. 2003, c. 3, s. 48; 2006, c. 21, Sched. F, s. 136 (1).

Transition

(7) The following documents issued by the Board, as they read immediately before this section came into force, shall be deemed to be codes issued under this section and the Board may change or amend the codes in accordance with this section and sections 70.2 and 70.3:

1. The Affiliate Relationships Code for Electricity Transmitters and Distributors.
2. The Distribution System Code.
3. The Electricity Retailer Code of Conduct.
4. The Retail Settlement Code.
5. The Transmission System Code.
6. Such other documents as are prescribed by the regulations. 2003, c. 3, s. 48.

Proposed codes, notice and comment

70.2 (1) The Board shall ensure that notice of every code that it proposes to issue under section 70.1 is given in such manner and to such persons as the Board may determine. 2003, c. 3, s. 48.

Content of notice

(2) The notice must include,

(a) the proposed code or a summary of the proposed code;

(b) a concise statement of the purpose of the proposed code;

(c) an invitation to make written representations with respect to the proposed code;

(d) the time limit for making written representations;

(e) if a summary is provided, information about how the entire text of the proposed code may be obtained; and

(f) a description of the anticipated costs and benefits of the proposed code. 2003, c. 3, s. 48.

Opportunity for comment

(3) On giving notice under subsection (1), the Board shall give a reasonable opportunity to interested persons to make written representations with respect to the proposed code within such reasonable period as the Board considers appropriate. 2003, c. 3, s. 48.

Exceptions to notice requirement

(4) Notice under subsection (1) is not required if what is proposed is an amendment that does not materially change an existing code. 2003, c. 3, s. 48.

Notice of changes

(5) If, after considering the submissions, the Board proposes material changes to the proposed code, the Board shall ensure notice of the proposed changes is given in such manner and to such persons as the Board may determine. 2003, c. 3, s. 48.

Content of notice

(6) The notice must include,

(a) the proposed code with the changes incorporated or a summary of the proposed changes;

(b) a concise statement of the purpose of the changes;

(c) an invitation to make written representations with respect to the proposed code;

(d) the time limit for making written representations;

(e) if a summary is provided, information about how the entire text of the proposed code may be obtained; and

(f) a description of the anticipated costs and benefits of the proposed code. 2003, c. 3, s. 48.

Representations re: changes

(7) On giving notice of changes, the Board shall give a reasonable opportunity to interested persons to make written representations with respect to the changes within such reasonable period as the Board considers appropriate. 2003, c. 3, s. 48.

Issuing the code

(8) If notice under this section is required, the Board may issue the code only at the end of this process and after considering all representations made as a result of that process. 2003, c. 3, s. 48.

Public inspection

(9) The Board must make the proposed code and the written representations made under this section available for public inspection during normal business hours at the offices of the Board. 2003, c. 3, s. 48.

Amendment of code

(10) In this section, a code includes an amendment to a code and a revocation of a code. 2003, c. 3, s. 48.

Effective date and gazette publication

70.3 (1) A code issued under section 70.1 comes into force on the day specified in the code. 2003, c. 3, s. 48.

Publication

(2) The Board shall publish every code that comes into force in *The Ontario Gazette* as soon after the code is issued as practicable. 2003, c. 3, s. 48.

Effect of non-publication

(3) A code that is not published is not effective against a person who has not had actual notice of it. 2003, c. 3, s. 48.

Effect of publication

(4) Publication of a code in *The Ontario Gazette*,

(a) is, in the absence of evidence to the contrary, proof of its text and of its issuance; and

(b) shall be deemed to be notice of its contents to every person subject to it or affected by it. 2003, c. 3, s. 48.

Judicial notice

(5) If a code is published in *The Ontario Gazette*, judicial notice shall be taken of it, of its content and of its publication. 2003, c. 3, s. 48.

Restriction on business activity

71. (1) Subject to subsection 70 (9) and subsection (2) of this section, a transmitter or distributor shall not, except through one or more affiliates, carry on any business activity other than transmitting or distributing electricity. 2004, c. 23, Sched. B, s. 12.

Exception

(2) Subject to section 80 and such rules as may be prescribed by the regulations, a transmitter or distributor may provide services in accordance with section 29.1 of the *Electricity Act, 1998* that would assist the Government of Ontario in achieving its goals in electricity conservation, including services related to,

(a) the promotion of electricity conservation and the efficient use of electricity;

(b) electricity load management; or

(c) the promotion of cleaner energy sources, including alternative energy sources and renewable energy sources. 2004, c. 23, Sched. B, s. 12.

Exception

(3) Despite subsection (1), a distributor may own and operate,

(a) a renewable energy generation facility that does not exceed 10 megawatts or such other capacity as may be prescribed by regulation and that meets any criteria that may be prescribed by the regulations;

(b) a generation facility that uses technology that produces power and thermal energy from a single source and that meets any criteria that may be prescribed by the regulations; or

(c) a facility that is an energy storage facility and that meets any criteria that may be prescribed by the regulations. 2009, c. 12, Sched. D, s. 11; 2011, c. 1, Sched. 4, s. 1.

Separate accounts

72. Every distributor shall keep its financial records associated with distributing electricity separate from its financial records associated with other activities. 1998, c. 15, Sched. B, s. 72.

Municipally-owned distributors

75. Repealed: 2003, c. 3, s. 49.

76. Repealed: 2003, c. 3, s. 50.

77. (1)-(4) Repealed: 2003, c. 3, s. 51 (1).

Cancellation of licence

(5) The Board may cancel a licence upon the request in writing of the licence holder. 1998, c. 15, Sched. B, s. 77 (5); 2003, c. 3, s. 51 (2).

(6) Repealed: 2000, c. 26, Sched. D, s. 2 (6).

Orders by Board, electricity rates

Order re: transmission of electricity

78. (1) No transmitter shall charge for the transmission of electricity except in accordance with an order of the Board, which is not bound by the terms of any contract. 2000, c. 26, Sched. D, s. 2 (7).

Order re: distribution of electricity

(2) No distributor shall charge for the distribution of electricity or for meeting its obligations under section 29 of the *Electricity Act, 1998* except in accordance with an order of the Board, which is not bound by the terms of any contract. 2000, c. 26, Sched. D, s. 2 (7).

Order re the Smart Metering Entity

(2.1) The Smart Metering Entity shall not charge for meeting its obligations under Part IV.2 of the *Electricity Act, 1998* except in accordance with an order of the Board, which is not bound by the terms of any contract. 2006, c. 3, Sched. C, s. 5 (1).

Note: On a day to be named by proclamation of the Lieutenant Governor, section 78 is amended by adding the following subsection:

Order re unit smart meter provider

(2.2) No unit smart meter provider shall charge for unit smart metering except in accordance with an order of the Board, which is not bound by the terms of any contract. 2010, c. 8, s. 38 (12).

See: 2010, c. 8, ss. 38 (12), 40.

Note: On a day to be named by proclamation of the Lieutenant Governor, section 78 is amended by adding the following subsection:

Order re unit sub-meter provider

(2.3) No unit sub-meter provider shall charge for unit sub-metering except in accordance with an order of the Board, which is not bound by the terms of any contract. 2010, c. 8, s. 38 (13).

See: 2010, c. 8, ss. 38 (13), 40.

Rates

(3) The Board may make orders approving or fixing just and reasonable rates for the transmitting or distributing of electricity or such other activity as may be prescribed and for the retailing of electricity in order to meet a distributor's obligations under section 29 of the *Electricity Act, 1998*. 2009, c. 12, Sched. D, s. 12 (1).

Note: On a day to be named by proclamation of the Lieutenant Governor, subsection (3) is amended by striking out "electricity or such other activity" and substituting "electricity, unit sub-metering or unit smart metering or such other activity". See: 2010, c. 8, ss. 38 (14), 40.

Note: On a day to be named by proclamation of the Lieutenant Governor, section 78 is amended by adding the following subsection:

Rates, unit sub-metering and unit smart-metering

(3.0.0.1) The Board shall, in accordance with rules prescribed by the regulations, make orders approving or fixing separate rates for unit sub-metering and for unit smart metering,

(a) for classes of consumers, as may be prescribed by regulation; and

(b) for different circumstances, as may be prescribed by regulation. 2010, c. 8, s. 38 (15).

See: 2010, c. 8, ss. 38 (15), 40.

Rates

(3.0.1) The Board may make orders approving or fixing just and reasonable rates for the Smart Metering Entity in order for it to meet its obligations under this Act or under Part IV.2 of the *Electricity Act, 1998*. 2006, c. 3, Sched. C, s. 5 (1).

Orders re deferral or variance accounts

(3.0.2) The Board may make orders permitting the Smart Metering Entity or distributors to establish one or more deferral or variance accounts related to costs associated with the smart metering initiative, in the circumstances prescribed in the regulations. 2006, c. 3, Sched. C, s. 5 (1).

Orders re recovery of smart metering initiative costs

(3.0.3) The Board may make orders relating to the ability of the Smart Metering Entity, distributors, retailers and other persons to recover costs associated with the smart metering initiative, in the situations or circumstances prescribed by regulation and the orders may require them to meet such conditions or requirements as may be prescribed, including providing for the time over which costs may be recovered. 2006, c. 3, Sched. C, s. 5 (1).

Orders re deferral or variance accounts, s. 27.2

(3.0.4) The Board may make orders permitting the IESO, distributors or other licensees to establish one or more deferral or variance accounts related to costs associated with complying with a directive issued under section 27.2. 2009, c. 12, Sched. D, s. 12 (2); 2014, c. 7, Sched. 23, s. 6 (1).

Methods re incentives or recovery of costs

(3.0.5) The Board may, in approving or fixing just and reasonable rates or in exercising the power set out in clause 70 (2) (e), adopt methods that provide,

(a) incentives to a transmitter or a distributor in relation to the siting, design and construction of an expansion, reinforcement or other upgrade to the transmitter's transmission system or the distributor's distribution system; or

(b) for the recovery of costs incurred or to be incurred by a transmitter or distributor in relation to the activities referred to in clause (a). 2009, c. 12, Sched. D, s. 12 (2).

Annual rate plan and separate rates for situations prescribed by regulation

(3.1) The Board shall, in accordance with rules prescribed by the regulations, approve or fix separate rates for the retailing of electricity,

(a) to such different classes of consumers as may be prescribed by the regulations; and

(b) for such different situations as may be prescribed by the regulations. 2004, c. 23, Sched. B, s. 14 (1).

Same

(3.2) The first rates approved or fixed by the Board under subsection (3.1) shall remain in effect for not less than 12 months and the Board shall approve or fix separate rates under subsection (3.1) after that time for periods of not more than 12 months each or for such shorter time periods as the Minister may direct. 2004, c. 23, Sched. B, s. 14 (1).

Rates to reflect cost of electricity

(3.3) In approving or fixing rates under subsection (3.1),

(a) the Board shall forecast the cost of electricity to be consumed by the consumers to whom the rates apply, taking into consideration the adjustments required under section 25.33 of the *Electricity Act, 1998* and shall ensure that the rates reflect these costs; and

(b) the Board shall take into account balances in the IESO's variance accounts established under section 25.33 of the *Electricity Act, 1998* and shall make adjustments with a view to eliminating those balances within 12 months or such shorter time periods as the Minister may direct. 2004, c. 23, Sched. B, s. 14 (1); 2014, c. 7, Sched. 23, s. 6 (2).

Forecasting cost of electricity

(3.4) In forecasting the cost of electricity for the purposes of subsection (3.3), the Board shall have regard to such matters as may be prescribed by the regulations. 2004, c. 23, Sched. B, s. 14 (1).

Imposition of conditions on consumer who enters into retail contract

(3.5) A consumer who enters into or renews a retail contract for electricity after the day he or she becomes subject to a rate approved or fixed under subsection (3.1) is subject to such conditions as may be determined by the Board. 2004, c. 23, Sched. B, 14 (1).

Rates

(4) The Board may make an order under subsection (3) with respect to the retailing of electricity in order to meet a distributor's obligations under section 29 of the *Electricity Act, 1998* even if the distributor is meeting its obligations through an affiliate or through another person with whom the distributor or an affiliate of the distributor has a contract. 1998, c. 15, Sched. B, s. 78 (4).

(5) Repealed: 2004, c. 23, Sched. B, s. 14 (2).

Same, obligations under s. 29 of *Electricity Act, 1998*

(5.0.1) In approving or fixing just and reasonable rates for the retailing of electricity in order to meet a distributor's obligations under section 29 of the *Electricity Act, 1998*, the Board shall comply with the regulations made under clause 88 (1) (g.5). 2003, c. 8, s. 1.

Same, Hydro One Inc. and subsidiaries

(5.1) In approving or fixing just and reasonable rates for Hydro One Inc. or a subsidiary of Hydro One Inc., the Board shall apply a method or technique prescribed by regulation for the calculation and treatment of transfers made by Hydro One Inc. or its subsidiary, as the case may be, that are authorized by section 50.1 of the *Electricity Act, 1998*. 2002, c. 1, Sched. B, s. 8; 2003, c. 3, s. 52 (2).

Same, statutory right to use corridor land

(5.2) In approving or fixing just and reasonable rates for a transmitter who has a statutory right to use corridor land (as defined in section 114.1 of the *Electricity Act, 1998*), the Board shall apply a method or technique prescribed by regulation for the treatment of the statutory right. 2002, c. 1, Sched. B, s. 8; 2003, c. 3, s. 52 (3).

Conditions, etc.

(6) An order under this section may include conditions, classifications or practices, including rules respecting the calculation of rates, applicable,

(a) to the Smart Metering Entity in respect of meeting its obligations;

(b) to an activity prescribed for the purposes of subsection (3); and

(c) to the transmission, distribution or retailing of electricity. 2009, c. 12, Sched. D, s. 12 (3).

Note: On a day to be named by proclamation of the Lieutenant Governor, clause (c) is repealed and the following substituted:

(c) to the transmission, distribution or retailing of electricity or unit sub-metering or unit smart metering.

See: 2010, c. 8, ss. 38 (16), 40.

Deferral or variance accounts

(6.1) If a distributor has a deferral or variance account that relates to the commodity of electricity, the Board shall, at least once every three months, make an order under this section that determines whether and how amounts recorded in the account shall be reflected in rates. 2003, c. 3, s. 52 (4).

Same

(6.2) If a distributor has a deferral or variance account that does not relate to the commodity of electricity, the Board shall, at least once every 12 months, or such shorter period as is prescribed by the regulations, make an order under this section that determines whether and how amounts recorded in the account shall be reflected in rates. 2003, c. 3, s. 52 (4).

Same

(6.3) An order that determines whether and how amounts recorded in a deferral or variance account shall be reflected in rates shall be made in accordance with the regulations. 2003, c. 3, s. 52 (4).

Same

(6.4) If an order that determines whether and how amounts recorded in a deferral or variance account shall be reflected in rates is made after the time required by subsection (6.1) or (6.2) and the delay is due in whole or in part to the conduct of a distributor, the Board may reduce the amount that is reflected in rates. 2003, c. 3, s. 52 (4).

Same

(6.5) If an amount recorded in a deferral or variance account of a distributor is reflected in rates, the Board shall consider the appropriate number of billing periods over which the amount shall be divided in order to mitigate the impact on consumers. 2003, c. 3, s. 52 (4).

Same

(6.6) Subsections (6.1), (6.2) and (6.4) do not apply unless section 79.6 has been repealed under section 79.11. 2003, c. 3, s. 52 (4).

Fixing other rates

(7) Upon an application for an order approving or fixing rates, the Board may, if it is not satisfied that the rates applied for are just and reasonable, fix such other rates as it finds to be just and reasonable. 1998, c. 15, Sched. B, s. 78 (7).

Burden of proof

(8) Subject to subsection (9), in an application made under this section, the burden of proof is on the applicant. 1998, c. 15, Sched. B, s. 78 (8).

Order

(9) If the Board of its own motion, or upon the request of the Minister, commences a proceeding to determine whether any of the rates that the Board may approve or fix under this section are just and reasonable, the Board shall make an order under subsection (3) and the burden of establishing that the rates are just and reasonable is on the transmitter or distributor, as the case may be. 1998, c. 15, Sched. B, s. 78 (9).

Note: On a day to be named by proclamation of the Lieutenant Governor, subsection (9) is repealed and the following substituted:

Order

(9) If the Board of its own motion, or upon the request of the Minister, commences a proceeding to determine whether any of the rates that the Board may approve or fix under this section are just and reasonable, the Board shall make an order under subsection (3) and the burden of establishing that the rates are just and reasonable is on the transmitter, distributor or unit sub-meter provider, as the case may be. 2010, c. 8, s. 38 (17).

See: 2010, c. 8, ss. 38 (17), 40.

Payments to prescribed generator

78.1 (1) The IESO shall make payments to a generator prescribed by the regulations with respect to output that is generated by a unit at a generation facility prescribed by the regulations. 2014, c. 7, Sched. 23, s. 7.

Payment amount

(2) Each payment referred to in subsection (1) shall be the amount determined in accordance with the order of the Board then in effect. 2014, c. 7, Sched. 23, s. 7.

(3) Repealed: 2014, c. 7, Sched. 23, s. 7.

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PART III - PROCEEDINGS

15. Commencement of Proceedings

15.01 Unless commenced by the Board, a proceeding shall be commenced by filing an application or a notice of appeal in compliance with these Rules, and within such a time period as may be prescribed by statute or the Board.

15.02 A person appealing an order made under the market rules shall file a notice of appeal within 15 calendar days after being served with a copy of the order, or within 15 calendar days of having completed making use of any provisions relating to dispute resolution set out in the market rules, whichever is later.

15.03 An appeal of an order, finding or remedial action made or taken by a standards authority referred to in section 36.3 of the *Electricity Act* shall be commenced by the Independent Electricity System Operator by notice of appeal filed within 15 calendar days after being served with a copy of the order or finding or of notice of the remedial action, or within 15 calendar days of receipt of notice of the final determination of any other reviews and appeals referred to in section 36.3(2) of the *Electricity Act*, whichever is later.

16. Applications

16.01 An application shall contain:

(a) a clear and concise statement of the facts;

(b) the grounds for the application;

(c) the statutory provision under which it is made; and

(d) the nature of the order or decision applied for.

16.02 An application shall be in such form as may be approved or specified by the Board and shall be accompanied by such fee as may be set for that purpose by the management committee under section 12.1(2) of the *OEB Act*.

PART VII - REVIEW

40. Request

40.01 Subject to **Rule 40.02**, any person may bring a motion requesting the Board to review all or part of a final order or decision, and to vary, suspend or cancel the order or decision.

40.02 A person who was not a party to the proceeding must first obtain the leave of the Board by way of a motion before it may bring a motion under **Rule 40.01**.

40.03 The notice of motion for a motion under **Rule 40.01** shall include the information required under **Rule 42**, and shall be filed and served within 20 calendar days of the date of the order or decision.

40.04 Subject to **Rule 40.05**, a motion brought under **Rule 40.01** may also include a request to stay the order or decision pending the determination of the motion.

40.05 For greater certainty, a request to stay shall not be made where a stay is precluded by statute.

40.06 In respect of a request to stay made in accordance with **Rule 40.04**, the Board may order that the implementation of the order or decision be delayed, on conditions as it considers appropriate.

41. Board Powers

41.01 The Board may at any time indicate its intention to review all or part of any order or decision and may confirm, vary, suspend or cancel the order or decision by serving a letter on all parties to the proceeding.

41.02 The Board may at any time, without notice or a hearing of any kind, correct a typographical error, error of calculation or similar error made in its orders or decisions.

42. Motion to Review

42.01 Every notice of a motion made under **Rule 40.01**, in addition to the requirements under **Rule 8.02**, shall:

(a) set out the grounds for the motion that raise a question as to the correctness of the order or decision, which grounds may include:

(i) error in fact;

(ii) change in circumstances;

(iii) new facts that have arisen;

(iv) facts that were not previously placed in evidence in the proceeding and could not have been discovered by reasonable diligence at the time; and

(b) if required, and subject to **Rule 40**, request a stay of the implementation of the order or decision or any part pending the determination of the motion.

43. Determinations

43.01 In respect of a motion brought under **Rule 40.01**, the Board may determine, with or without a hearing, a threshold question of whether the matter should be reviewed before conducting any review on the merits.

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Ontario Energy Board

RETAIL SETTLEMENT CODE

Revision Date: October 01, 2011

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1 GENERAL AND ADMINISTRATIVE PROVISIONS

1.1 Purpose of the Code

This Code sets the minimum obligations that a distributor and retailer must meet in determining the financial settlement costs of electricity retailers and consumers and in facilitating service transaction requests where a competitive retailer provides service to a consumer. These obligations arise through sections 26 through 31, inclusive, of the *Electricity Act, 1998* and the conditions of distributions' licences and retailers' licences.

1.2 Definitions

"*Act*" means the *Ontario Energy Board Act, 1998*, S.O. 1998, c.15, Schedule B.

7.6 Reconnection

A distributor may refuse to reconnect a consumer as long as the consumer remains in arrears on payment for competitive electricity services provided under SSS or for non-competitive electricity services. A distributor's right to refuse re-connection may be exercised regardless of whether a consumer requests service under SSS or from a retailer. Where a distributor reconnects a property in which a consumer is served by a retailer, the distributor shall promptly notify the retailer.

7.7 Billing Errors

The following rules apply to billing errors in respect of which Measurement Canada has not become involved in the dispute:

7.7.1

Where a distributor has over billed a customer or retailer by an amount that is equal or exceeds the customer's or retailer's average monthly billing amount, determined in accordance with section 7.7.5, the distributor shall, within 10 days of determination of the error, notify the customer or retailer of the over billing and advise that the customer or retailer may elect to have the full amount credited to their account or repaid in full by cheque, within 11 days of requesting payment by cheque. Where the customer or retailer has not requested payment by cheque within 10 days of notification of the error by the distributor, the distributor may credit the full amount to the account.

7.7.2

Where a distributor has over billed a customer or retailer by an amount that is less than the customer's or retailer's average monthly billing amount, determined in accordance with section 7.7.5, the distributor shall credit the account in the next regularly scheduled bill issued to the customer or retailer.

7.7.3

If there are outstanding arrears on the customer's or retailer's account, the distributor is not required to repay the over-billed amount but may apply it to the arrears on the customer's or retailer's account and credit or repay to the customer or retailer the remaining balance.

7.7.4

Where a distributor has under billed a customer who is not responsible for the error, the distributor shall allow the customer to pay the under-billed amount in equal instalments over a period at least equal to the duration of the billing error, up to a maximum of 2 years.

7.7.4.1

Where a distributor issues a bill to a customer for an under-billed amount, the distributor shall notify the customer that, if the customer is an eligible low-income customer, he or she has the option of paying the under-billed amount as follows:

i) in accordance with section 7.7.4; or

ii) over a period of 10 months where the under-billed amount is less than twice the customer's average monthly billing and over a period of 20 months where the under-billed amount equals or exceeds twice the customer's average monthly billing.

7.7.4.2

For the purposes of section 7.7.4.1, the distributor may notify the customer by way of bill insert, bill message, letter or outgoing telephone message.

7.7.5

For the purposes of sections 7.7.1, 7.7.2 and 7.7.4.1, the customer's or retailer's average monthly billing amount shall be calculated by taking the aggregate of the total electricity charges billed to the customer or retailer in the most recent 12 months, including adjustment for the impact of any known billing error(s), and dividing that value by 12. If the customer has been receiving service from a distributor for less than 12 months, the customer's average monthly billing amount shall be based on a reasonable estimate made by the distributor. For the purposes of this section, "electricity charges" has the same meaning as in section 2.6.6.3 of the Distribution System Code, subject to any adjustments necessary to take into account other electricity-related charges billed to non-residential customers.

7.7.6

Where a distributor has under billed a customer or retailer who is responsible for the error, whether by way of tampering, willful damage, unauthorized energy use or other unlawful actions, the distributor may require payment of the full under-billed amount by means of a corresponding charge on the next regularly scheduled bill issued to the customer or retailer or on a separate bill to be issued to the customer or retailer responsible for the error. Where disconnection has occurred, the distributor may require payment of such bill prior to the reconnection of service upon request by the customer responsible for the tampering, willful damage, unauthorized energy use or other unlawful actions that caused the under billing.

7.7.7

Where the distributor has under billed a customer or retailer, the maximum period of under billing for which the distributor is entitled to be paid is 2 years. Where the distributor has over billed a customer or retailer, the maximum period of over billing for which the customer or retailer is entitled to be repaid is 2 years.

7.7.8

A distributor may charge interest on under-billed amounts only where the customer or retailer was responsible for the error, whether by way of tampering, willful damage, unauthorized energy use or other unlawful actions. Such interest shall be equal to the prime rate charged by the distributor's bank.

7.7.9

A distributor that has over billed a customer or retailer and the billing error is not the result of a distributor’s standard documented billing practices, shall pay interest on the amount credited or repaid to the customer or retailer equal to the prime rate charged by the distributor’s bank.

7.7.10

The entity billing a customer, whether it is a distributor or retailer, is responsible for advising the customer of any meter error and of his, her or its rights and obligations under the *Electricity and Gas Inspection Act (Canada).*The billing party is also responsible for subsequently settling actual payment differences with the customer as described above.

7.7.11

The provisions of section 7.7 do not apply where the distributor has over billed or under billed a customer or retailer but issues a corrected bill within 16 days of the issue date of the original erroneous bill.

8 SECURITY ARRANGEMENTS BETWEEN DISTRIBUTORS AND RETAILERS

A distributor shall enter into security arrangements with each retailer to protect against the risk of payment default by the retailer. The terms of these arrangements, including the magnitude and type of security required and the planned frequency and timing for updating the security arrangements as market share and other determining factors change, shall be set out in the Service Agreement. The amount and type of security required may vary based on estimates of the magnitude of exposure, determined according to the provisions of section 8.1 below, and the creditworthiness of the retailer.

8.1 Estimating the Magnitude of Exposure

The magnitude of exposure that a distributor faces will vary with factors such as: the number of consumers served by a retailer, the average consumption of consumers served by the retailer: the length of the billing cycle (e.g. 30 days, 60 days, etc.); and the type of billing in place (e.g. retailer-consolidated or distributor-consolidated or split billing). A distributor shall apply the due, a distributor shall immediately notify a retailer that payment was not received and work with the retailer to remedy the situation. After 10 business days, if the account remains unpaid and the parties have not agreed on a remedy, the distributor may notify the retailer's consumers that they will become SSS consumers according to a schedule determined by the distributor unless such consumers elect to receive supply from another retailer. If the distributor receives an STR that identifies an alternative retailer prior to switching a consumer to SSS, the distributor shall process the STR and switch the consumer to the new retailer rather than back to SSS.

During a default period, a distributor shall not retain any revenues collected by the distributor on behalf of the retailer as security unless the magnitude of security accessible to the distributor is insufficient to cover the amount of the default.

A distributor may charge a retailer and a retailer may charge a distributor interest on any overdue settlement payments at a rate equal to the prime rate charge by the bank of the party which is owed money plus 2 per cent per annum.

A distributor may charge a retailer for the cost of final meter reads and other allowable transaction costs associated with transferring consumers back to SSS based on the applicable rates approved by the Board under section 78 of the *Act*.

9 SETTLEMENT DISPUTE PROCEDURES

Any disputes between retailers, embedded retail generators or consumers and distributors concerning the implementation of a distributor's responsibilities under this Code shall be settled according to the dispute mechanism specified by the Board in a distributor's licence. Disputes concerning the settlement amount billed or owed by a distributor to a retailer or an embedded retail generator do not relieve either party from their obligations to make payment in full at the time payment is due. Any deviations between the amount paid at the time due and the amount determined through the dispute resolution process shall be subject to payment of interest. The interest rate shall equal the prime rate charged by the distributor's bank.

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Electricity Distribution Licence

ED-2002-0499

Essex Powerlines Corporation

Valid Until

December 21, 2023

Original signed by

____

Kirsten Walli
Board Secretary
Ontario Energy Board

Date of Issuance: December 22, 2003
Date of Last Amendment: December 18, 2014

Ontario Energy Board
P.O. Box 2319
2300 Yonge Street
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LIST OF AMENDMENTS

Board File No.	**Date of Amendment**
EB-2010-0215	November 12, 2010
EB-2011-0072	June 14, 2011
EB-2014-0324	December 18, 2014

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1 Definitions

In this Licence:

"**Accounting Procedures Handbook**" means the handbook, approved by the Board which specifies the accounting records, accounting principles and accounting separation standards to be followed by the Licensee;

"**Act**" means the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Schedule B;

"**Affiliate Relationships Code for Electricity Distributors and Transmitters**" means the code, approved by the Board which, among other things, establishes the standards and conditions for the interaction between electricity distributors or transmitters and their respective affiliated companies;

"**Conservation and Demand Management**" and "**CDM**" means distribution activities and programs to reduce electricity consumption and peak provincial electricity demand;

"**Conservation and Demand Management Code for Electricity Distributors**" means the code approved by the Board which, among other things, establishes the rules and obligations surrounding Board approved programs to help distributors meet their CDM Targets;

"**distribution services**" means services related to the distribution of electricity and the services the Board has required distributors to carry out, including the sales of electricity to consumers under section 29 of the Act, for which a charge or rate has been established in the Rate Order;

"**Distribution System Code**" means the code approved by the Board which, among other things, establishes the obligations of the distributor with respect to the services and terms of service to be offered to customers and retailers and provides minimum, technical operating standards of distribution systems;

"**Electricity Act**" means the *Electricity Act, 1998*, S.O. 1998, c. 15, Schedule A;

"**IESO**" means the Independent Electricity System Operator;

"**Licensee**" means Essex Powerlines Corporation

"**Market Rules**" means the rules made under section 32 of the Electricity Act;

"**Net Annual Peak Demand Energy Savings Target**" means the reduction in a distributor's peak electricity demand persisting at the end of the four-year period (i.e. December 31, 2014) that coincides with the provincial peak electricity demand that is associated with the implementation of CDM Programs;

"**Net Cumulative Energy Savings Target**" means the total amount of reduction in electricity consumption associated with the implementation of CDM Programs between 2011-2014;

"**OPA**" means the Ontario Power Authority;

“**Performance Standards**” means the performance targets for the distribution and connection activities of the Licensee as established by the Board in accordance with section 83 of the Act;

“**Provincial Brand**” means any mark or logo that the Province has used or is using, created or to be created by or on behalf of the Province, and which will be identified to the Board by the Ministry as a provincial mark or logo for its conservation programs;

“**Rate Order**” means an Order or Orders of the Board establishing rates the Licensee is permitted to charge;

“**regulation**” means a regulation made under the Act or the Electricity Act;

“**Retail Settlement Code**” means the code approved by the Board which, among other things, establishes a distributor’s obligations and responsibilities associated with financial settlement among retailers and consumers and provides for tracking and facilitating consumer transfers among competitive retailers;

“**service area**” with respect to a distributor, means the area in which the distributor is authorized by its licence to distribute electricity;

“**Standard Supply Service Code**” means the code approved by the Board which, among other things, establishes the minimum conditions that a distributor must meet in carrying out its obligations to sell electricity under section 29 of the Electricity Act;

“**wholesaler**” means a person that purchases electricity or ancillary services in the IESO administered markets or directly from a generator or, a person who sells electricity or ancillary services through the IESO-administered markets or directly to another person other than a consumer.

2 Interpretation

2.1 In this Licence, words and phrases shall have the meaning ascribed to them in the Act or the Electricity Act. Words or phrases importing the singular shall include the plural and vice versa. Headings are for convenience only and shall not affect the interpretation of the licence. Any reference to a document or a provision of a document includes an amendment or supplement to, or a replacement of, that document or that provision of that document. In the computation of time under this licence, where there is a reference to a number of days between two events, they shall be counted by excluding the day on which the first event happens and including the day on which the second event happens. Where the time for doing an act expires on a holiday, the act may be done on the next day that is not a holiday.

3 Authorization

3.1 The Licensee is authorized, under Part V of the Act and subject to the terms and conditions set out in this Licence:

a) to own and operate a distribution system in the service area described in Schedule 1 of this Licence;

b) to retail electricity for the purposes of fulfilling its obligation under section 29 of the Electricity Act in the manner specified in Schedule 2 of this Licence; and

c) to act as a wholesaler for the purposes of fulfilling its obligations under the Retail Settlement Code or under section 29 of the Electricity Act.

4 Obligation to Comply with Legislation, Regulations and Market Rules

4.1 The Licensee shall comply with all applicable provisions of the Act and the Electricity Act and regulations under these Acts, except where the Licensee has been exempted from such compliance by regulation.

4.2 The Licensee shall comply with all applicable Market Rules.

5 Obligation to Comply with Codes

5.1 The Licensee shall at all times comply with the following Codes (collectively the “Codes”) approved by the Board, except where the Licensee has been specifically exempted from such compliance by the Board. Any exemptions granted to the licensee are set out in Schedule 3 of this Licence. The following Codes apply to this Licence:

a) the Affiliate Relationships Code for Electricity Distributors and Transmitters;

b) the Distribution System Code;

c) the Retail Settlement Code; and

d) the Standard Supply Service Code.

5.2 The Licensee shall:

a) make a copy of the Codes available for inspection by members of the public at its head office and regional offices during normal business hours; and

b) provide a copy of the Codes to any person who requests it. The Licensee may impose a fair and reasonable charge for the cost of providing copies.

6 Obligation to Provide Non-discriminatory Access

6.1 The Licensee shall, upon the request of a consumer, generator or retailer, provide such consumer, generator or retailer with access to the Licensee’s distribution system and shall convey electricity on behalf of such consumer, generator or retailer in accordance with the terms of this Licence.

7 Obligation to Connect

7.1 The Licensee shall connect a building to its distribution system if:

a) the building lies along any of the lines of the distributor’s distribution system; and

b) the owner, occupant or other person in charge of the building requests the connection in writing.

7.2 The Licensee shall make an offer to connect a building to its distribution system if:

a) the building is within the Licensee's service area as described in Schedule 1; and

b) the owner, occupant or other person in charge of the building requests the connection in writing.

7.3 The terms of such connection or offer to connect shall be fair and reasonable and made in accordance with the Distribution System Code, and the Licensee's Rate Order as approved by the Board.

7.4 The Licensee shall not refuse to connect or refuse to make an offer to connect unless it is permitted to do so by the Act or a regulation or any Codes to which the Licensee is obligated to comply with as a condition of this Licence.

8 Obligation to Sell Electricity

8.1 The Licensee shall fulfill its obligation under section 29 of the Electricity Act to sell electricity in accordance with the requirements established in the Standard Supply Service Code, the Retail Settlement Code and the Licensee's Rate Order as approved by the Board.

9 Obligation to Maintain System Integrity

9.1 The Licensee shall maintain its distribution system in accordance with the standards established in the Distribution System Code and Market Rules, and have regard to any other recognized industry operating or planning standards adopted by the Board.

10 Market Power Mitigation Rebates

10.1 The Licensee shall comply with the pass through of Ontario Power Generation rebate conditions set out in Appendix A of this Licence.

11 Distribution Rates

11.1 The Licensee shall not charge for connection to the distribution system, the distribution of electricity or the retailing of electricity to meet its obligation under section 29 of the Electricity Act except in accordance with a Rate Order of the Board.

12 Separation of Business Activities

12.1 The Licensee shall keep financial records associated with distributing electricity separate from its financial records associated with transmitting electricity or other activities in accordance with the Accounting Procedures Handbook and as otherwise required by the Board.

13 Expansion of Distribution System

13.1 The Licensee shall not construct, expand or reinforce an electricity distribution system or make an interconnection except in accordance with the Act and Regulations, the Distribution System Code and applicable provisions of the Market Rules.

13.2 In order to ensure and maintain system integrity or reliable and adequate capacity and supply of electricity, the Board may order the Licensee to expand or reinforce its distribution system in accordance with Market Rules and the Distribution System Code, or in such a manner as the Board may determine.

14 Provision of Information to the Board

14.1 The Licensee shall maintain records of and provide, in the manner and form determined by the Board, such information as the Board may require from time to time.

14.2 Without limiting the generality of paragraph 14.1 the Licensee shall notify the Board of any material change in circumstances that adversely affects or is likely to adversely affect the business, operations or assets of the Licensee as soon as practicable, but in any event no more than twenty (20) days past the date upon which such change occurs.

14.3 The licensee shall inform the Board as soon as possible of any material changes to the service agreement with Essex Power Corporation and Essex Power Services Corporation (the "Service Agreement").

14.4 If either party to the Service Agreement provides notice of its intention to exercise a right to terminate or discontinue any services under the services agreement, the Licensee shall:

a) Immediately notify the Board in writing of the notice; and

b) provide a plan to the Board as soon as possible, but no later than ten (10) days after the receipt of the notice, as to how the affected distribution services will be maintained in compliance with the terms of this Licence.

14.5 In the event of termination of the Service Agreement for any reason, the Licensee shall:

a) ensure there is no interruption of distribution services to the consumers as a result of the termination;

b) notify the Board of the name of the new company that will provide the distribution services; and

c) file with the Board the distribution services agreement with the new company.

15 Restrictions on Provision of Information

15.1 The Licensee shall not use information regarding a consumer, retailer, wholesaler or generator obtained for one purpose for any other purpose without the written consent of the consumer, retailer, wholesaler or generator.

15.2 The Licensee shall not disclose information regarding a consumer, retailer, wholesaler or generator to any other party without the written consent of the consumer, retailer, wholesaler or generator, except where such information is required to be disclosed:

a) to comply with any legislative or regulatory requirements, including the conditions of this Licence;

b) for billing, settlement or market operations purposes;

c) for law enforcement purposes; or

d) to a debt collection agency for the processing of past due accounts of the consumer, retailer, wholesaler or generator.

15.3 The Licensee may disclose information regarding consumers, retailers, wholesalers or generators where the information has been sufficiently aggregated such that their particular information cannot reasonably be identified.

15.4 The Licensee shall inform consumers, retailers, wholesalers and generators of the conditions under which their information may be released to a third party without their consent.

15.5 If the Licensee discloses information under this section, the Licensee shall ensure that the information provided will not be used for any other purpose except the purpose for which it was disclosed.

16 Customer Complaint and Dispute Resolution

16.1 The Licensee shall:

a) have a process for resolving disputes with customers that deals with disputes in a fair, reasonable and timely manner;

b) publish information which will make its customers aware of and help them to use its dispute resolution process;

c) make a copy of the dispute resolution process available for inspection by members of the public at each of the Licensee’s premises during normal business hours;

d) give or send free of charge a copy of the process to any person who reasonably requests it; and

e) subscribe to and refer unresolved complaints to an independent third party complaints resolution service provider selected by the Board. This condition will become effective on a date to be determined by the Board. The Board will provide reasonable notice to the Licensee of the date this condition becomes effective.

17 Term of Licence

17.1 This Licence shall take effect on December 22, 2003 and expire on December 21, 2023. The term of this Licence may be extended by the Board.

18 Fees and Assessments

18.1 The Licensee shall pay all fees charged and amounts assessed by the Board.

19 Communication

19.1 The Licensee shall designate a person that will act as a primary contact with the Board on matters related to this Licence. The Licensee shall notify the Board promptly should the contact details change.

19.2 All official communication relating to this Licence shall be in writing.

19.3 All written communication is to be regarded as having been given by the sender and received by the addressee:

a) when delivered in person to the addressee by hand, by registered mail or by courier;

b) ten (10) business days after the date of posting if the communication is sent by regular mail; and

c) when received by facsimile transmission by the addressee, according to the sender's transmission report.

20 Copies of the Licence

20.1 The Licensee shall:

a) make a copy of this Licence available for inspection by members of the public at its head office and regional offices during normal business hours; and

b) provide a copy of this Licence to any person who requests it. The Licensee may impose a fair and reasonable charge for the cost of providing copies.

21 Conservation and Demand Management

21.1 2011-2014 Conservation and Demand Management Framework

21.1.1 The Licensee shall achieve reductions in electricity consumption and reductions in peak provincial electricity demand through the delivery of CDM programs. The Licensee shall meet its 2014 Net Annual Peak Demand Savings Target of 7.190 MW, and its 2011-2014 Net Cumulative Energy Savings Target of 21.540 GWh (collectively the "CDM Targets"), over a four-year period beginning January 1, 2011.

21.1.2 The Licensee shall meet its CDM Targets through:

a) the delivery of Board approved CDM Programs delivered in the Licensee's service area ("Board-Approved CDM Programs");

b) the delivery of CDM Programs that are made available by the OPA to distributors in the Licensee's service area under contract with the OPA ("OPA-Contracted Province-Wide CDM Programs"); or

c) a combination of a) and b).

21.1.3 The Licensee shall make its best efforts to deliver a mix of CDM Programs to all consumer types in the Licensee's service area.

21.1.4 The Licensee shall comply with the rules mandated by the Board's Conservation and Demand Management Code for Electricity Distributors.

21.1.5 The Licensee shall utilize the common Provincial brand, once available, with all Board-Approved CDM Programs, OPA-Contracted Province-Wide Programs, and in conjunction with or co-branded with the Licensee's own brand or marks.

21.2 2015-2020 Conservation and Demand Management Framework

21.2.1 The Licensee shall, between January 1, 2015 and December 31, 2020, make CDM programs, available to customers in its licensed service area and shall, as far as is appropriate and reasonable having regard to the composition of its customer base, do so in relation to each customer segment in its service area ("CDM Requirement").

21.2.2 The CDM programs referred to in item 21.2.1 above shall be designed to achieve reductions in electricity consumption.

21.2.3 The Licensee shall meet its CDM Requirement by:

a) making Province-Wide Distributor CDM Programs, funded by the Ontario Power Authority (the "OPA"), available to customers in its licensed service area;

b) making Local Distributor CDM Programs, funded by the OPA, available to customers in its licensed service area; or

c) a combination of a) and b).

21.2.4 The Licensee shall, as far as possible having regard to any confidentiality or privacy constraints, make the details and results of Local Distributor CDM Programs available to other licensed electricity distributors upon request.

21.2.5 The Licensee shall, as far as possible having regard to any confidentiality or privacy constraints, make the details and results of Local Distributor CDM Programs available to any other person upon request.

21.2.6 The Licensee shall report to the OPA the results of the CDM programs in accordance with the requirements of the licensee's "CDM-related" contract with the OPA.

SCHEDULE 1 DEFINITION OF DISTRIBUTION SERVICE AREA

This Schedule specifies the area in which the Licensee is authorized to distribute and sell electricity in accordance with paragraph 8.1 of this Licence.

1. The Town of La Salle as of June 1, 1991
2. The Town of Amherstburg as of December 31, 1997
3. The Town of Tecumseh and the Village of St. Clair Beach as of December 31, 1998
4. The Town of Leamington as of December 31, 1998

SCHEDULE 2 PROVISION OF STANDARD SUPPLY SERVICE

This Schedule specifies the manner in which the Licensee is authorized to retail electricity for the purposes of fulfilling its obligation under section 29 of the Electricity Act.

1. The Licensee is authorized to retail electricity directly to consumers within its service area in accordance with paragraph 8.1 of this Licence, any applicable exemptions to this Licence, and at the rates set out in the Rate Orders.

SCHEDULE 3 LIST OF CODE EXEMPTIONS

This Schedule specifies any specific Code requirements from which the Licensee has been exempted.

1. The Licensee is exempt from the requirements of section 2.5.3 of the Standard Supply Service Code with respect to the price for small volume/residential consumers, subject to the Licensee offering an equal billing plan as described in its application for exemption from Fixed Reference Price, and meeting all other undertakings and material representations contained in the application and the materials filed in connection with it.

2. The Licensee is exempt from the requirement to implement time-of-use pricing as of the mandatory date for its RPP customers with eligible time-of-use meters as required under the Standard Supply Service Code for Electricity Distributors. The mandatory time-of-use pricing date exemption expires on December 31, 2011.

APPENDIX A

MARKET POWER MITIGATION REBATES

1 Definitions and Interpretations

In this Licence

"embedded distributor" means a distributor who is not a market participant and to whom a host distributor distributes electricity;

"embedded generator" means a generator who is not a market participant and whose generation facility is connected to a distribution system of a distributor, but does not include a generator who consumes more electricity than it generates;

"host distributor" means a distributor who is a market participant and who distributes electricity to another distributor who is not a market participant.

In this Licence, a reference to the payment of a rebate amount by the IESO includes interim payments made by the IESO.

2. Information Given to IESO

a Prior to the payment of a rebate amount by the IESO to a distributor, the distributor shall provide the IESO, in the form specified by the IESO and before the expiry of the period specified by the IESO, with information in respect of the volumes of electricity withdrawn by the distributor from the IESO-controlled grid during the rebate period and distributed by the distributor in the distributor's service area to:

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998.*

b Prior to the payment of a rebate amount by the IESO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the embedded distributor shall provide the host distributor, in the form specified by the IESO and before the expiry of the period specified in the Retail Settlement Code, with the volumes of electricity distributed during the rebate period by the embedded distributor's host distributor to the embedded distributor net of any electricity distributed to the embedded distributor which is attributable to embedded generation and distributed by the embedded distributor in the embedded distributor's service area to:

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*.

c Prior to the payment of a rebate amount by the IESO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the host distributor shall provide the IESO, in the form specified by the IESO and before the expiry of the period specified by the IESO, with the information provided to the host distributor by the embedded distributor in accordance with section 2.

The IESO may issue instructions or directions providing for any information to be given under this section. The IESO shall rely on the information provided to it by distributors and there shall be no opportunity to correct any such information or provide any additional information and all amounts paid shall be final and binding and not subject to any adjustment.

For the purposes of attributing electricity distributed to an embedded distributor to embedded generation, the volume of electricity distributed by a host distributor to an embedded distributor shall be deemed to consist of electricity withdrawn from the IESO-controlled grid or supplied to the host distributor by an embedded generator in the same proportion as the total volume of electricity withdrawn from the IESO-controlled grid by the distributor in the rebate period bears to the total volume of electricity supplied to the distributor by embedded generators during the rebate period.

3. Pass Through of Rebate

A distributor shall promptly pass through, with the next regular bill or settlement statement after the rebate amount is received, any rebate received from the IESO, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt, to:

a retailers who serve one or more consumers in the distributor’s service area where a service transaction request as defined in the Retail Settlement Code has been implemented;

b consumers who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998* and who are not served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

c embedded distributors to whom the distributor distributes electricity.

The amounts paid out to the recipients listed above shall be based on energy consumed and calculated in accordance with the rules set out in the Retail Settlement Code. These payments may be made by way of set off at the option of the distributor.

If requested in writing by OPGI, the distributor shall ensure that all rebates are identified as coming from OPGI in the following form on or with each applicable bill or settlement statement:

“ONTARIO POWER GENERATION INC. rebate”

Any rebate amount which cannot be distributed as provided above or which is returned by a retailer to the distributor in accordance with its licence shall be promptly returned to the host distributor or IESO as applicable, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt.

Nothing shall preclude an agreement whereby a consumer assigns the benefit of a rebate payment to a retailer or another party.

Pending pass-through or return to the IESO of any rebate received, the distributor shall hold the funds received in trust for the beneficiaries thereof in a segregated account.

ONTARIO POWER GENERATION INC. REBATES

For the payments that relate to the period from May 1, 2006 to April 30, 2009, the rules set out below shall apply.

1. Definitions and Interpretations

In this Licence

"embedded distributor" means a distributor who is not a market participant and to whom a host distributor distributes electricity;

"embedded generator" means a generator who is not a market participant and whose generation facility is connected to a distribution system of a distributor, but does not include a generator who consumes more electricity than it generates;

"host distributor" means a distributor who is a market participant and who distributes electricity to another distributor who is not a market participant.

In this Licence, a reference to the payment of a rebate amount by the IESO includes interim payments made by the IESO.

2. Information Given to IESO

a Prior to the payment of a rebate amount by the IESO to a distributor, the distributor shall provide the IESO, in the form specified by the IESO and before the expiry of the period specified by the IESO, with information in respect of the volumes of electricity withdrawn by the distributor from the IESO-controlled grid during the rebate period and distributed by the distributor in the distributor's service area to:

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented and the consumer is not receiving the prices established under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*; and

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*.

b Prior to the payment of a rebate amount by the IESO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the embedded distributor shall provide the host distributor, in the form specified by the IESO and before the expiry of the period specified in the Retail Settlement Code, with the volumes of electricity distributed during the rebate period by the embedded distributor's host distributor to the embedded distributor net of any electricity distributed to the embedded distributor which is attributable to embedded generation and distributed by the embedded distributor in the embedded distributor's service area to:

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*.

c Prior to the payment of a rebate amount by the IESO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the host distributor shall provide the IESO, in the form specified by the IESO and before the expiry of the period specified by the IESO, with the information provided to the host distributor by the embedded distributor in accordance with section 2.

The IESO may issue instructions or directions providing for any information to be given under this section. The IESO shall rely on the information provided to it by distributors and there shall be no opportunity to correct any such information or provide any additional information and all amounts paid shall be final and binding and not subject to any adjustment.

For the purposes of attributing electricity distributed to an embedded distributor to embedded generation, the volume of electricity distributed by a host distributor to an embedded distributor shall be deemed to consist of electricity withdrawn from the IESO-controlled grid or supplied to the host distributor by an embedded generator in the same proportion as the total volume of electricity withdrawn from the IESO-controlled grid by the distributor in the rebate period bears to the total volume of electricity supplied to the distributor by embedded generators during the rebate period.

3. Pass Through of Rebate

A distributor shall promptly pass through, with the next regular bill or settlement statement after the rebate amount is received, any rebate received from the IESO, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt, to:

a retailers who serve one or more consumers in the distributor’s service area where a service transaction request as defined in the Retail Settlement Code has been implemented and the consumer is not receiving the prices established under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*;

b consumers who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998* and who are not served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

c embedded distributors to whom the distributor distributes electricity.

The amounts paid out to the recipients listed above shall be based on energy consumed and calculated in accordance with the rules set out in the Retail Settlement Code. These payments may be made by way of set off at the option of the distributor.

If requested in writing by OPGI, the distributor shall ensure that all rebates are identified as coming from OPGI in the following form on or with each applicable bill or settlement statement:

“ONTARIO POWER GENERATION INC. rebate”

Any rebate amount which cannot be distributed as provided above or which is returned by a retailer to the distributor in accordance with its licence shall be promptly returned to the host distributor or IESO as applicable, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt.

Nothing shall preclude an agreement whereby a consumer assigns the benefit of a rebate payment to a retailer or another party.

Pending pass-through or return to the IESO of any rebate received, the distributor shall hold the funds received in trust for the beneficiaries thereof in a segregated account.