BOARD STAFF RESPONSE TO UNDERTAKING OF BOMA

UNDERTAKING TCU1.1

REF: Tr.1 p15

DR. KAUFMANN TO PROVIDE DECISION OF MAINE COMMISSION AND EVIDENCE OF DR. LOWRY

RESPONSE

Please see the attached documents:

- Central Maine Power Company, Request for New Alternative Rate Plan ("ARP 2014"), Order of Partial Dismissal, August 2, 2013

- Supplemental Productivity Offset Factor, Supplemental Testimony of Dr. Mark N. Lowry on behalf of Central Maine Power Company, September 20, 2013

Witness: Dr. Lawrence Kaufmann, PEG

STATE OF MAINE
PUBLIC UTILITIES COMMISSION

Docket No. 2013-00168

August 2, 2013

CENTRAL MAINE POWER COMPANY,
Request for New Alternative Rate Plan
("ARP 2014")

ORDER OF PARTIAL
DISMISSAL

WELCH, Chairman; Littell and Vannoy, Commissioners

I. SUMMARY

With this Order, we grant the Motion for Partial Dismissal of the Office of the Public Advocate (OPA) pursuant to Section 10(G)(2) of Chapter 110 of the Commission's Rules of Practice and Procedure and thus dismiss Central Maine Power Company's (CMP or Company) Capital Expenditure Recovery Mechanism (CRM) included as part of its request for approval of a new Alternate Rate Plan (ARP). In granting the OPA's Motion, we find that CMP's own evidence does not provide a basis for deciding the CRM proposal in CMP's favor, that proceeding to hearing will needlessly prolong the decision-making process causing undue burden and expense to the parties and to the Commission, and that there are no additional policy reasons present here to allow the CRM Proposal to remain in the case.

II. BACKGROUND

A. CMP's Proposal

On May 1, 2013, pursuant to the provisions of CMP's current ARP (ARP 2008), CMP filed revenue requirement information for calendar 2012 consistent with the applicable requirements of Section 5 of Chapter 120 of the Commission Rules. *See Central Maine Power Company, Chapter 120 Information (Post ARP 2000), Transmission and Distribution Utility Revenue Requirements and Rate Design and Request for Alternate Rate Plan*, Docket No. 2007-215, Order Approving Stipulation. Stipulation at P. 39 (July 1, 2008). As part of its Revenue Requirement filing, CMP requested a rate increase effective July 1, 2014 as well as a request for a new ARP (ARP 2014) which would run from January 1, 2014 through December 31, 2018. Under CMP's proposal, rate changes for the capital portion of CMP's revenue requirement would not increase based on the inflation minus X formula used in CMP's prior ARPs and also proposed to be used in this ARP for CMP's operations and maintenance (O&M) costs. Instead, under CMP's proposal the Commission would set a projected capital revenue requirement that would include depreciation, property tax costs and return on investment, over the five-year ARP period. The Company's pre-filed testimony contains a proposed budget (Exhibit CAP-2) that includes various forecasted costs associated with the Company's capital investment plan.

The CRM as proposed by CMP has three components. Under the first component, applicable to most of CMP's distribution plant, plant investments would be reconciled under CMP's Net Plant Reconciliation Mechanism. For this category of investments, for each year during ARP 2014 that CMP achieves its SAIFI and CAIDI reliability targets, CMP would carry forward any net plant savings arising during that year. At the end of ARP 2014, if CMP met its proposed capital program metrics[1] and the net plant balance on December 31, 2018 was less than the targeted level but within a bandwidth of 10%, then CMP would retain the revenue requirement associated with the net plant savings. If the cumulative net plant savings were greater than 10%, then CMP would return to customers the revenue requirement related to the net plant savings that were in excess of 10%, but the Company would continue to retain the revenue requirement associated with the net plant savings that were within the 10% bandwidth. If the Company failed to meet any capital program metric during the term of ARP2014, CMP would obtain no incentive.

This net plant reconciliation mechanism would not apply to CMP's proposed Customer Relationship Management and Billing system investment. CMP estimates this investment to be $55 million. Costs for the Customer Relationship Management and Billing system would be fully reconciled and could increase above its current estimate.[2] Finally, as clarified by CMP, costs for capital programs that have common transmission and distribution related components, and other IT, would be subject to downward reconciliation but not the incentive mechanism.

The proposed revenue requirement increases (in millions) associated with the CRM during the period of the ARP are as follows:

CRM Proposed Rate Changes ($ in Millions)			
RY2 (Effective 7/15)	RY3 (Effective 7/16)	RY4 (Effective 7/17)	RY5 (Effective 7/18)
$10.9	$12.7	$10.3	$5.4

[1] The capital program metrics include number of automated reclosers installed, number of substations modernized, number of conductor miles replaced and/or installed, number of substation transformers and breakers replaced and number of substations modernized.

[2] The estimated cost for the Customer Relationship Management and Billing program is $55 million. However, the Company acknowledges that it "intends to revisit this estimate *as more detailed information about the scope of the Customer Relationship Management and Billing is developed*" and plans to issue a request for proposal at a later time to solicit competitive bids for the implementation for a system integrator that would represent approximately 60% of the costs of the program.

B. The OPA Motion

On June 19, 2013, the OPA filed a Motion and Brief in Support of Partial Dismissal seeking dismissal of CMP's CRM. In its motion, the OPA argues that the proposal to recover forecasted capital additions during each year of ARP 2014 outside the traditional price index formula inappropriately shifts the risks and burdens from the Company to ratepayers. The OPA also states that the proposal places an unreasonable regulatory burden upon the Commission and intervenors by requiring an enormous degree of pre-review to fully investigate the projects and related costs. The OPA adds that such a rate mechanism will decrease the Company's responsibility to manage the risks associated with its capital expenditures and creates the very incentive to overcapitalize recognized by the Commission in *Central Maine Power, Proposed Increase in Rates,* Docket No. 92-345, (Dec. 14, 1993) Order at 140.

The OPA asserts that the Company has failed to meet its burden of proof that the rates produced by the CRM will be just and reasonable. First, the Company is not actually committed to spending at any particular level or on a particular item. By allowing the Company to retain the first 10% of savings, the Company has created an incentive to overestimate investment costs in contravention to the requirement of 35-A M.R.S. § 3195. By treating capital expenditures separately and indexing O&M costs, the OPA asserts that the Company has developed a methodology which also creates the risk that savings associated with increased capital spending will not be passed on to customers. Finally, with regard to the Company's proposal for its Customer Relationship Management and Billing system software change out, the OPA claims that the Company's proposal places the risk of cost overruns entirely on ratepayers and is contrary to the provisions of 35-A M.R.S. § 3195.

C. CMP's Response

CMP argues that through its pre-filed testimony the Company has met its evidentiary burden and that its proposal is a reasonable rate-adjustment mechanism that conforms with Maine law and Maine's incentive ratemaking statute. See 35-A M.R.S. § 3195. The Company argues that Section 3195 specifically allows rate incentive mechanisms based on forecasted costs and also authorizes plans which include a reconciliation mechanism. CMP asserts that the capital program will result in just and reasonable rates. CMP argues that the OPA has not pointed to any specific component of the CRM that will result in rates that are not just and reasonable and that the incentive mechanism and the downward reconciliation mechanism ensures that rates will be just and reasonable. In addition, CMP claims that any savings created during this ARP will result in a lower rate base which will be passed on eventually to ratepayers in subsequent proceedings. With regard to the OPA's claim that the Company will be incentivized to inflate its forecast and five-year projection, the Company argues that the adjudicatory nature of this proceeding provides the process to ensure that the forecast is not inflated.

CMP argues that the CRM is necessary because under current conditions, the use of the price adjustment formula of inflation less a productivity offset that was used in CMP's prior alternative rate plans would not provide adequate revenues over the ARP 2014 term to cover the annual increases in CMP's distribution revenue requirements needed to fund the Company's planned capital investments. CMP asserts that this revenue shortfall will result in either less capital investment than is needed to ensure safe, reasonable and adequate service in the future, or a steady erosion of CMP's returns to far below just and reasonable levels. CMP notes that, as an alternative to granting the CRM projection of revenue requirements over the five year ARP, the Company could file five individual rate proposals. Finally, the Company argues that it is in the public interest to allow the case to go forward and even if the Company had not met its burden of proof at this point in the case, the Commission should exercise its discretion and allow the case to go forward.

III. LEGAL STANDARD GOVERNING THE MOTION

Under Chapter 110 of the Commission's Rules of Practice and Procedure, the Commission may dismiss a party's case when the pre-filed testimony does not satisfy the party's evidentiary burden. See Chapter 110, 10(G)(2) ("If the prefiled testimony standing alone does not satisfy the party's evidentiary burden, that party's case may be dismissed upon motion of a party").[3] A motion to dismiss under Section 10(G)(2) of Chapter 110 of our Rules can be seen as the procedural equivalent of a Motion for Judgment as a Matter of Law under Rule 50(d) of the Maine Rules of Civil Procedure. See *Bangor Hydro-Electric Company, Proposed Schedule to Provide for Residential Heat Pump Service Rate,* Docket No. 92-255, Order of Dismissal (March 26, 1993) (*Bangor Hydro*).

In *Bangor Hydro*, the Commission noted that the rationale for the procedural mechanism under Section 10(G)(2) (then codified in Section 934 of Chapter 110) is clear; if the petitioner's own evidence does not provide a basis for deciding the case in its favor, proceeding to hearings will needlessly prolong the decision making process causing undue burden and expense to the parties and for the Commission.

When faced with a Section 10(G)(2) motion, because the petitioner has had the opportunity to present its case in the manner of its own choosing, the petitioner is not entitled to any inferences that go beyond that evidence in its favor. *Public Utilities Commission Investigation Into New England Telephone Company's Cost of Service and Rate Design,* Docket No. 92-130, Order Denying Motions (Jan. 5, 1993) (*New England Telephone)*. In *New England Telephone* the Commission went on to conclude, however, that if the petitioner's direct case was not of such quality to meet the applicable statutory standards, the Commission could either: 1) dismiss it in whole or

[3] See 35-A M.R.S. § 1314 (In all original proceedings before the commission where an increase in rates, tolls, charges, schedules or joint rate is complained of, *the burden of proof is on the public utility to show that the increase is just and reasonable*.) (emphasis added).

part; or 2) in the alternative, allow the case to proceed in order to allow petitioner's overall views to remain on the record to be compared and contrasted with the evidentiary presentations and positions of other parties. The Commission reasoned that Option 2 was available because neither Rule 50(d) nor Rule 934 are mandatory, and further stated:[4]

> Rule 50(d) states in pertinent part: "The court as trier of the facts may then determine them [the facts] and render judgment against the plaintiff or may decline to render any judgment until the close of all the evidence." Similarly, Rule 934 of our Rules states that "if the pre filed testimony standing alone does not satisfy the party's evidentiary burden, that case may be dismissed upon motion of a party." Dismissal of portions of [New England Telephone's] case under these rules, then, even if legally justifiable, need not be ordered if there are policy or other reasons to allow [New England Telephone's] case to remain as originally filed.

New England Telephone at 10.

IV. DISCUSSION AND DECISION

Rate adjustment mechanisms that encourage utilities "to promote efficiency in transmission and distribution utility operations and least-cost planning" are authorized by 35-A M.R.S. §3195. In determining the reasonableness of any rate adjustment mechanism under section 3195, the Commission must apply the standards of section 301, the "just and reasonable rate provision." The Law Court in *Industrial Energy Consumer Group v. Public Utilities Commission*, 773 A. 2d 1038 (Me. 2001) concluded that the "just and reasonable standard" does not signify a single rate and that in determining whether a rate is just and reasonable the Commission may consider issues in addition to rate of return.

The Commission has previously approved a number of price-cap rate plans under the provisions of Section 3195 to encourage efficiencies and cost effectiveness. In the precursor to CMP's first ARP, the Commission identified the following benefits and objectives of an ARP:

(1) Electricity prices continue to be regulated in a comprehensible and predictable way;

(2) Rate predictability and stability are more likely;

(3) Regulatory "administration" costs can be reduced, thereby allowing for the conduct of other important regulatory activities and for CMP to expend more time and resources in managing its operations;

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[4] As stated above Section 934 of current Chapter 110 of the Commission's was the predecessor counterpart to Section 10(G)(2) of the prior version of Chapter 110.

> (4) Risks can be shifted to shareholders and away from ratepayers (in a way that is manageable from the utility's financial perspective); and
>
> (5) Because exceptional cost management can lead to enhanced profitability for shareholders, stronger incentives for cost minimization are created.

Central Maine Power Company, Proposed Increase in Rates, Docket No. 92-345, Order at 130 (Dec. 14, 1993). In considering the question of whether capital investments should be treated as part of the general price cap formula, the Commission in that case went on to say:

> A reason for not treating capital expenditures separately is that it would help eliminate the oft-discussed problem of ROR regulation giving firms an incentive to overcapitalize (the so-called "Averch-Johnson effect"). As an additional reason, by incorporating all capital expenditures for each category of resource … into the price cap formula, the company would have an incentive to make least-cost investment decisions. The Commission believes that such treatment of new capital expenditures should reduce the need for retrospective prudence reviews of CMP's planning activities.

Id. at 140.

Generally, utility ratemaking can be split into two basic approaches: cost of service ratemaking which is based on test year results adjusted for known and measurable changes, and incentive ratemaking which ties rate changes to factors other than the utility's actual costs. CMP's CRM Mechanism is a creative combination of the two approaches, but in doing so CMP has created a mechanism that is fundamentally inconsistent with each of the two approaches.

First, the CRM is incompatible with cost of service ratemaking since it goes far beyond known and certain adjustments to the test year. CMP’s proposal includes a summary (Exhibit CAP-2) five-year budget for capital expenditures. This budget consists of overall line item costs for broad categories (e.g., distribution transformers, transformer disposal, regulators, meters, etc.) for each year of the ARP. None of the figures presented in the proposed budget are based on specific projects or plant upgrades that will be made over the five-year period. To further complicate matters, CMP proposes to reserve the ability to “reprioritize” or “rearrange” projects during the ARP, stating that, “[f]uture events and circumstances may change the schedules, scopes and cost estimates for the capital investment projects included within CMP’s Capital Investment Plan during ARP 2014.” Capital Testimony at 5. Thus, even if the majority of capital investment under CMP’s CRM program were based on substantial evidence, the Company could change the capital projects employed (as well as the expenditures) over the course of the ARP.

Under the CRM, CMP's proposed Customer Relationship Management and Billing project would be subject to full reconciliation. The estimated cost for this project is $55 million. However, the Company acknowledges it "intends to revisit this estimate *as more detailed information about the scope of the CRM&B is developed*" and intends, prior to the project, to issue a request for proposal to solicit competitive bids for a system integrator that would represent approximately 60% of the costs. The broad discretion sought by CMP to reprioritize capital investments over the five-year plan, coupled with the fully reconcilable nature of the CRM&B for which accurate cost estimates are lacking, undermine the Commission's goals of predictability, stability, and comprehensiveness in setting electricity rates.

At the same time, the CRM is also inconsistent with the price cap principles set forth above. By tying CMP's profits to the level of investments, the CRM removes one of the core objectives of an ARP, the elimination of the incentive to over-capitalize. As part of the CRM, CMP has proposed that it would retain the first 10% of savings associated with capital spending and then flow the remainder of savings to ratepayers. This particular mechanism does little to reduce the incentive for CMP to overestimate both the need for capital improvements and the costs of such improvements.

In addition, since capital spending can and often does result in O&M savings, by subjecting O&M costs to the inflation minus X formula while capital costs are subject to CRM process, the CRM would create a mismatch of cost and savings that is contrary to general regulatory ratemaking principles. In effect, customers would be subject to increased capital costs while depriving them of the corresponding benefits of O&M savings.

We are also not persuaded by CMP's arguments that its 6-year capital distribution plan should be fully vetted and blessed by the Commission in this proceeding. Detailed long-term capital planning is an activity that, at least in detail, should be left to management subject to prudency review. In addition, as a practical matter, by requiring that the parties and the Commission pre-approved specific capital programs years in advance, whenever CMP acknowledges that there is uncertainty relating to the timing, cost and even the ultimate need for the projects, the CRM introduces a level of predictive uncertainty into the ratemaking process that we find to be unacceptable.

We disagree with the Company's suggestion that we should defer consideration of its program at this time until all of the evidence has been considered. Although such a practice would be permissible under our precedent, we do not believe that a year-long proceeding that would include significant discovery, multiple rounds of testimony, and staff recommendations, will sufficiently reduce the level of uncertainty concerning the details of the CRM program to warrant committing ratepayer funds for the term of a five-year ARP.[5] We thus conclude that the OPA's Motion for Partial Dismissal should be granted.

We recognize that our decision here will require CMP to amend certain parts of its case. To the extent that CMP believes that increased capital spending is necessary during the coming years, we do not believe that our Order here either precludes CMP from pursuing such investments or from the recovery of such investments. We do not order any portion of CMP's testimony to be stricken from the record. CMP may propose another mechanism which allows for increased capital investments without shifting the risk of over estimation and uncertainty to the ratepayers. Or CMP may argue that some elements of that testimony are relevant and probative in settling, for example, the initial rate levels for an ARP and/or the productivity effort to be applied.

We do not posit on any particular mechanism that would be suitable in this case or suggest an approach that should be sought by CMP. Such a decision should be left to Company management, subject to review by the Commission for general standards of prudence and reasonableness in accordance with Commission precedent and Sections 301 and/or 3195. However, to the extent that CMP continues to believe that a significant increase in capital spending is necessary in order to ensure safe, reliable and adequate service as part of any revised proposal, we would observe that CMP's CRM proposal has highlighted an interesting problem, namely how to deal with under-investment during one ARP when moving to the next. For example, an ARP without specific capital commitments could provide the utility with an opportunity to allow its system to degrade in order to keep profits high. If the next ARP does contain such commitments (and recovery) the utility might have the opportunity to recover the cost of capital that arguably should have been spent in prior years. Put another way, moving from an RPI-X regulatory system as a discipline on management behavior to a capital program of the kind proposed by CMP is especially problematic because it could reward underinvestment by a utility. The issue of whether CMP has allowed its system to degrade is, of course, an issue that may need to be addressed in this case notwithstanding the elimination of the CRM proposal, as such degradation could be relevant to a determination of just and reasonable rate levels.[6]

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[5] In reaching our decision, we do not rely on the finding urged by the OPA that the amount of time that would be required on the part of Staff or the parties to fully vet CMP's proposal would be impracticable or unduly burdensome though we acknowledge the amount of Commission and party effort in a case must fall within the realm of what is practicable, feasible and possible within statutory time frames and current and foreseeable resource constraints.

[6] To the extent there may be an issue with an upgrade to the Customer Relationship Management and Billing system being necessary to achieve the customer benefits and savings envisioned in implementation of the Advanced Metering Infrastructure System, that issue should be examined as part of the management audit to be conducted as part of this proceeding where the costs and benefits of the AMI system are being examined by the Commission.

Accordingly, we

ORDER

That the OPA's Motion for a Partial Dismissal of the portion of CMP's May 1, 2013 filing consisting of CMP's proposed CRM proposal and the associated incentive mechanism is granted.

Dated at Hallowell, Maine, this 2nd day of August, 2013.

BY ORDER OF THE COMMISSION

__________*/s/ Harry Lanphear*__________
Harry Lanphear
Administrative Director

COMMISSIONERS VOTING FOR: Welch
Littell
Vannoy

NOTICE OF RIGHTS TO REVIEW OR APPEAL

5 M.R.S. § 9061 requires the Public Utilities Commission to give each party to an adjudicatory proceeding written notice of the party's rights to review or appeal of its decision made at the conclusion of the adjudicatory proceeding. The methods of review or appeal of PUC decisions at the conclusion of an adjudicatory proceeding are as follows:

1. Reconsideration of the Commission's Order may be requested under Section 11(D) of the Commission's Rules of Practice and Procedure (65-407 C.M.R. 110) within 20 days of the date of the Order by filing a petition with the Commission stating the grounds upon which reconsideration is sought. Any petition not granted within 20 days from the date of filing is denied.

2. Appeal of a final decision of the Commission may be taken to the Law Court by filing, within 21 days of the date of the Order, a Notice of Appeal with the Administrative Director of the Commission, pursuant to 35-A M.R.S. § 1320(1)-(4) and the Maine Rules of Appellate Procedure.

3. Additional court review of constitutional issues or issues involving the justness or reasonableness of rates may be had by the filing of an appeal with the Law Court, pursuant to 35-A M.R.S. § 1320(5).

Note: The attachment of this Notice to a document does not indicate the Commission's view that the particular document may be subject to review or appeal. Similarly, the failure of the Commission to attach a copy of this Notice to a document does not indicate the Commission's view that the document is not subject to review.

STATE OF MAINE PUBLIC UTILITIES COMMISSION

DOCKET NO. 2013-00168

CENTRAL MAINE POWER COMPANY
REQUEST FOR NEW ALTERNATIVE RATE PLAN
("ARP 2014")

SUPPLEMENTAL PRODUCTIVITY OFFSET FACTOR

September 20, 2013

Mark N. Lowry
Pacific Economics Group Research, LLC

On behalf of
Central Maine Power Company
83 Edison Drive
Augusta, ME 04336

TABLE OF CONTENTS

1. INTRODUCTION AND SUMMARY

Central Maine Power Company (the "Company" or "CMP") is proposing a new alternative rate plan ("ARP") for its power distribution services. The attrition relief mechanism ("ARM") of the ARP is a key issue in its design. Faced with slow volume growth in a period of mounting investment needs, the Company is proposing that the ARP feature revenue decoupling.

In its initial filing, the Company also proposed an ARM with a "hybrid" design. The budget for operation and maintenance ("O&M") expenses would be escalated each year by an index based on industry input price and productivity research. The budget for capital cost would have a predetermined stairstep trajectory based on a Company cost forecast.

This general approach to ARM design was rejected by the Maine Public Utilities Commission ("MPUC" or "Commission"). The commissioners, in their deliberation on the issue, stressed that a workable approach to supplemental compensation for high capital expenditures ("capex") should limit the role of forecasting and preserve strong performance incentives. The Company is now proposing that budgets for most of its capital cost as well as its O&M be escalated by a single index-based ARM. This ARM provides some supplemental revenue that would help fund investments but preserves strong incentives because it is based on the productivity trends of other utilities.

1.1 Qualifications of Witness

This report was prepared by Dr. Mark Newton Lowry of Pacific Economics Group ("PEG") Research LLC, an economic consulting firm that is prominent in the field of ARP design. Research on revenue decoupling and empirical issues, such as input price and productivity trends of utilities, which are salient in ARM design are Company specialties. The team he leads has over 60 man-years of experience in the field of statistical utility cost research. CMP has retained PEG Research to prepare a study on the price and productivity trends of Northeast power distributors to support the development of an ARM for the proposed new ARP.

Dr. Lowry is the President of PEG Research. In that capacity, he has for many years supervised statistical research on input price and productivity trends of electricity and natural gas utilities. He has testified or filed commentary on industry productivity trends and other ARP design issues more than twenty five times, including three previous occasions in Maine. He has also testified several times on revenue decoupling. Other venues for his testimony have included Alberta, British Columbia, California, Colorado, the District of Columbia, Hawaii, Illinois, Kentucky, Georgia, Maryland, Massachusetts, New Jersey, Oklahoma, Ontario, Oregon, New York, Quebec, Vermont, and Washington. His practice is international in scope and has also included projects in Australia, Europe, Japan, and Latin America. Work for diverse clients has given him a reputation for objectivity and dedication to regulatory science.

Before joining PEG, Dr. Lowry worked for many years at Christensen Associates in Madison, first as a senior economist and later as a Vice President and director of Regulatory Strategy. The key members of his group have joined him at PEG. Dr. Lowry's career has also included work as an academic economist. He has served as an Assistant Professor of Mineral Economics at the Pennsylvania State University and as a visiting professor at the Ecole des Hautes Etudes Commerciales in Montreal. His academic research and teaching stressed the use of mathematical theory and statistical methods in industry analysis. He has been a referee for several scholarly journals and has an extensive record of professional publications and public appearances. He holds a doctoral degree in applied economics from the University of Wisconsin-Madison.

1.2 Revenue Cap Design

ARPs with revenue decoupling require an ARM to escalate rates between rate cases. Most commonly, the ARM escalates allowed revenue. Input price and productivity research is useful in ARM design. The key drivers of utility cost are input prices, productivity, and operating scale. A sensible index-based formula for allowed revenue escalation is:

$$\textit{growth Revenue} = \textit{Inflation} - X + \textit{growth Customers}.$$

The X factor and customer growth terms can be consolidated, producing a lower "consolidated" X factor that produces the same result.

$$\textit{growth Revenue} = \textit{Inflation} - (X - \textit{growth Customers})$$
$$= \textit{Inflation} - X^{Consolidated}$$

1.3 Empirical Findings

In the empirical research for CMP, multifactor input price and productivity indexes have been calculated for two samples of northeast power distributors for which good data are available. The growth trends of these indexes were then compared to those of analogous indexes for the U.S. economy. Established methods and publicly available data from respected sources were used in developing the indexes.

The 2002-2011 sample period and the groups of sampled utilities were carefully chosen. The end date of the sample period is the latest for which the data used to construct the utility indexes are as yet available. The year 2002 is a good start date because it provides a ten year period in which the effects of industry restructuring on the general cost of utilities were quite limited. Two Northeast regions were considered in our research. The first, which we will call the "upper" Northeast, was defined as upper New York State and New England. This region has been used in previous indexing studies prepared for ARP proceedings in Maine and has been favored by Bench Staff. The second Northeast region considered, which we will call the "broad" Northeast, adds utilities in the mid-Atlantic region.

The multifactor productivity ("MFP") of the sampled upper Northeast power distributors was found to average **0.56%** growth per annum. During the same period, the federal government's MFP index for the U.S. private business sector averaged **1.11%** annual growth. The productivity differential was thus **-0.55%**.

The trend in the multifactor input price index for the sampled power distributors averaged 3.55% growth per annum. The corresponding trend in an input price index for the U.S. economy was estimated to be about **3.20%**. The resultant input price differential of about **-0.35%** suggests that the input price growth facing Northeast power distributors was very similar to and a little more rapid than that facing the typical firm in our economy.

The MFP of the sampled broad Northeast power distributors was found to average **1.06%** growth per annum. The productivity differential was thus **-0.05%**. The trend in the multifactor input price index for the broad Northeast power distributors averaged **3.44%** growth per annum. The resultant input price differential was **-0.24%**.

CMP increased its capital expenditures ("capex") considerably in 2011 and expects capex to remain at higher levels during the years of the proposed ARP. PEG has undertaken statistical research to compute an adjustment to the X factor appropriate for a typical northeast utility in need of high capex. The resultant K factor would not weaken CMP's performance incentives or require a review of its cost forecasts. Our research suggests a K factor that would reduce X by 63 basis points for the upper Northeast and by 36 basis points for the broad Northeast.

The stretch factor component of an X factor is designed to facilitate the sharing of the benefits of performance improvements that may be encouraged by the plan's strong incentives. The need for sharing depends in part on the Company's operating efficiency at the start of the plan. CMP experienced superior MFP growth during the sample period. This should have brought it to a level of performance that is at the very least average for the industry, and possibly better.

The need for sharing depends as well on whether the proposed ARP is expected to generate stronger performance incentives than those under which the sampled distributors operated. The proposed ARP has a five year term but also contains a provision to share surplus earnings. Meanwhile, the average interval between rate cases of the sampled power distributors was about 4.8 years for the upper Northeast utilities and 5.9 years for the broad Northeast utilities. Earnings sharing mechanisms were uncommon in the broad Northeast. These considerations suggest that the stretch factor for CMP should be 0.00%.

To summarize, the research using data for the upper Northeast region that is preferred by Bench Staff suggests a consolidated X factor of **-1.90%**. This is the sum of a **-0.55%** productivity differential, a **-0.35%** input price differential, a **-0.63%** K factor, a **0.00%** stretch factor, and **-0.37%** forecasted customer growth. The research using broad Northeast data suggests an X factor of **-1.02%** for CMP. This is the sum of a **-0.05%** productivity differential, a **-0.24%** input price differential, a **-0.36%** K factor, a 0.00% stretch factor, and a **-0.37%** offset for forecasted customer growth.

2. ARM DESIGN

ARPs are the most common approach to utility regulation around the world today. In such plans, a moratorium is typically placed on general rate cases for several years. An ARM usually adjusts allowed rates or revenues automatically for changing business conditions between rate cases. These mechanisms are designed before the start of the plan and are external in the sense that they are insensitive to the costs of the utility during the plan period.

The ARM is one of the most important components of an ARP. Such mechanisms can substitute for rate cases as a means to adjust utility rates for trends in input prices, operating scale, and other external business conditions that affect utility earnings. As such, they make it possible to extend the period between rate cases and strengthen utility performance incentives. The mechanism can be designed so that the expected benefits of improved performance are shared equitably between utilities and their customers.

ARMs can escalate rates or allowed revenue. Price caps have been widely used to regulate industries, such as telecommunications, for which it is important to promote marketing flexibility while protecting core customers from cross-subsidization. Under traditional rate designs, which involve high usage charges, price caps make utility earnings sensitive to system use. Since cost is insensitive to use in the short and medium term, utilities are incented to encourage greater use. A price cap approach made sense for CMP when it was vertically integrated because it afforded the Company more flexibility in marketing to the price-sensitive industrial sector, which included many paper mills.

Under revenue caps, the focus of escalator design is the growth in the allowed revenue needed to afford compensation for growing cost. Allowed revenue is sometimes called the target revenue, revenue requirement, or "budget". The allowed revenue yielded by a revenue cap escalator in a given year must be converted into rates, and this conversion depends on billing determinants.

Revenue caps are often paired with a revenue decoupling mechanism that removes the utility's disincentive to promote efficient energy use. However, revenue caps have intuitive appeal with or without decoupling since revenue cap escalators deal with the drivers of *cost* growth, whereas price cap escalators must consider the more complicated issue of the *difference* between cost and billing determinant growth. As a consequence, revenue caps are sometimes used even in the absence of decoupling. Current examples of companies operating under revenue caps without decoupling include Green Mountain Power in Vermont and two gas utilities in Alberta.

2.1 Basic Indexing Concepts

The logic of economic indexes provides the rationale for using price and productivity research to design ARMs for revenue decoupling plans. To understand the logic it is helpful to first have a high level understanding of input price and productivity indexes.

2.1.1 Input Price and Quantity Indexes

The growth trend in a company's cost can be shown to be the sum of the growth in an appropriately designed input price index ("*Input Prices*") and input quantity index ("*Inputs*").

$$\textit{trend Cost} = \textit{trend Input Prices} + \textit{trend Inputs}. \qquad [1]$$

These indexes summarize trends in the input prices and quantities that make up cost. Both indexes use the cost share of each input group that is itemized in index design as weights. A cost-weighted input price index measures the impact of input price inflation on the cost of a bundle of inputs. A cost-weighted input quantity index measures the impact of input quantity growth on cost. Capital, labor, and miscellaneous materials and services are the major classes of base rate inputs used by power distributors such as CMP.

The calculation of input quantity indexes is complicated by the fact that firms typically use numerous inputs in service provision. This complication can be contained when summary input price indexes are readily available for a group of inputs such as labor. Rearranging the terms of [1] we obtain

$$\textit{growth Inputs} = \textit{growth Cost} - \textit{growth Input Prices}. \qquad [2]$$

Input quantity growth is calculated as the growth in inflation-adjusted (a/k/a "real") cost.

This is the approach to input quantity trend calculation that is most widely used in utility productivity research. We can, for example, calculate the growth in the quantity of labor by taking the difference between salary and wage expenses and a salary and wage price index.

2.1.2 Productivity Indexes

Basic Idea

A productivity index is the ratio of an output quantity index ("*Outputs*") to an input quantity index.

$$Productivity = \frac{Outputs}{Inputs}. \qquad [3]$$

It is used to measure the efficiency with which firms convert production inputs into outputs. Some productivity indexes are designed to measure productivity *trends*. The growth trend of such a productivity index is the *difference* between the trends in the output and input quantity indexes.

$$trend\ Productivity = trend\ Outputs - trend\ Inputs. \qquad [4]$$

Productivity grows when the output index rises more rapidly (or falls less rapidly) than the input index. Productivity can be volatile but tends to grow over time. The volatility is due to fluctuations in output and the uneven timing of certain expenditures. Volatility tends to be greater for individual companies than for an aggregation of companies such as a regional industry.

The scope of a productivity index depends on the array of inputs that are considered in the input quantity index. Some indexes measure productivity in the use of a single input class such as labor. A *multifactor* productivity ("MFP") index measures productivity in the use of multiple inputs. A *total factor* productivity ("TFP") index measures productivity in the use of *all* inputs. Indexes used in ARM design are sometimes called TFP indexes, but are better described as MFP indexes because multiple input categories are considered but some inputs (*e.g.*, purchased power) are usually excluded.

Output Indexes

The output (quantity) index of a firm or industry summarizes trends in individual outputs. Growth in each output dimension that is itemized is measured by a subindex. In designing an output index, choices concerning subindexes and weights should depend on the manner in which the index is to be used. One possible objective is to measure the impact of output growth on *revenue*. In that event the subindexes should measure trends in *billing determinants* and the weight for each itemized determinant should be its share of revenue.[1] In this report we denote a revenue-weighted output index by $Outputs^R$. A productivity index that is calculated using $Outputs^R$ will be labeled $Productivity^R$.

$$trend\ Productivity^R = trend\ Outputs^R - trend\ Inputs. \qquad [5a]$$

Another possible objective of output research is to measure the impact of output growth on *cost*. In that event it can be shown that the subindexes should measure the dimensions of operating scale or "workload" that drive cost. If there is more than one pertinent scale variable, the weights for each variable should reflect the relative cost impacts of these drivers. The sensitivity of cost to the change in a business condition variable is commonly measured by its cost "elasticity". Elasticities can be estimated econometrically using data on the operations of a group of utilities. A multi-category output index with elasticity weights is unnecessary if econometric research reveals that there is one dominant cost driver. A productivity index that is calculated using a cost-based output index will be labeled $Productivity^C$.

$$trend\ Productivity^C = trend\ Outputs^C - trend\ Inputs. \qquad [5b]$$

This may fairly be described as a "cost efficiency index".

Sources of Productivity Growth

Research by economists has found the sources of productivity growth to be diverse. One important source is technological change. New technologies permit an industry to produce given output quantities with fewer inputs.

Economies of scale are another important source of productivity growth. These economies are available in the longer run if cost has a tendency to grow less rapidly than the scale of operations. A company's potential to achieve incremental scale economies

[1] This approach to output quantity indexation was developed by the French economist Francois Divisia.

depends on the pace of its workload growth. Incremental scale economies (and thus productivity growth) will typically be reduced the slower is output growth.

A third important source of productivity growth is change in X inefficiency. X inefficiency is the degree to which a company fails to operate at the maximum efficiency that technology and other external business conditions allow. Productivity growth will increase (decrease) to the extent that X inefficiency diminishes (increases). The potential of a company for productivity growth from this source is greater the lower is its current efficiency level.

Another driver of productivity growth is changes in the miscellaneous business conditions, other than input price inflation and workload growth, which affect cost. A good example for an electric power distributor is the share of distribution lines that are undergrounded. Because underground lines are more costly, an increase in the percentage of lines that are undergrounded will tend to slow MFP growth.

When productivity is calculated using a revenue-based output index it is easy to show that the trend in $Productivity^R$ can be decomposed into the trend in the cost efficiency index and the difference between the trends in revenue- and cost-based output indexes.

$$\begin{aligned} &trend\ Productivity^R \\ &= trend\ Productivity^C + (trend\ Outputs^R - trend\ Outputs^C) \end{aligned} \quad [6]$$

This difference in parentheses, which we will call the "output differential", addresses the different ways that output growth affects revenue and cost. The output differential can be an important driver of $Productivity^R$ growth. For example, if $Outputs^C$ is growing more rapidly than $Outputs^R$, growth in $Productivity^R$ can be materially slowed.

2.2 Use of Index Research in ARM Design

Research on the input price and productivity trends of utilities has been used for more than twenty years to design ARMs. This approach produces automatic adjustments for changing business conditions without weakening a utility's performance incentives. The indexing approach also has the benefit of exposing the utility to an external productivity growth standard. The utility can bolster earnings by achieving productivity growth that is superior to the standard. For this reason, ARPs that feature index-based ARMs are sometimes called performance-based rate making ("PBR") plans.

This approach to ARM design originated in the United States where detailed, standardized data on costs of a large number of utilities have been available for many years from state and federal agencies. First applied in the railroad industry, index-based ARMs have subsequently been used to regulate telecom, gas, electric, and oil pipeline utilities. Maine was one of the first jurisdictions to use this approach in energy utility regulation. The methodology is now used in several additional countries.

ARMs based on indexing research are now used more widely to regulate utilities in Canada than in the United States. For example power distributors in Ontario currently operate under PBR plans with index-based ARMs. All gas and electric distributors in Alberta are required to operate under PBR plans with index-based ARMs.

2.2.1 Price Cap Indexes

Early work to use indexing in ARM design focused chiefly on *price* cap indexes ("PCIs"). We begin our explanation of the logic for such research (a/k/a "index logic") by considering the growth in the prices charged by an industry that earns, in the long run, a competitive rate of return.[2] In such an industry, the long-run trend in revenue equals the long-run trend in cost.

$$\textit{trend Revenue} = \textit{trend Cost}. \qquad [7]$$

The trend in the revenue of any firm or industry can be shown to be the sum of the trends in revenue-weighted indexes of its output prices ("*Output Prices*") and billing determinants.

$$\textit{trend Revenue} = \textit{trend Outputs}^R + \textit{trend Output Prices}. \qquad [8]$$

Recollecting from [2] that the trend in cost is the sum of the growth in cost-weighted input price and quantity indexes, it follows that the trend in output prices that permits revenue to track cost is the difference between the trends in an input price index and a multifactor productivity index of MFP^R form.

$$\textit{trend Output Prices}^R = \textit{trend Input Prices} - (\textit{trend Outputs}^R - \textit{trend Inputs}) \qquad [9]$$

[2] The assumption of a competitive rate of return applies to unregulated, competitively structured markets. It is also applicable to utility industries and even to individual utilities.

$$= trend\ Input\ Prices - trend\ MFP^R.$$

The result in [9] provides a conceptual framework for the design of PCIs of general form

$$trend\ Rates = trend\ Inflation - X. \quad [10a]$$

Here X, the "X factor", is calibrated to reflect a base MFP^R growth target ("$\overline{MFP^R}$"). A "stretch factor", established in advance of plan operation, is sometimes added to the formula. The stretch factor slows PCI growth in a manner that shares with customers the financial benefits of performance improvements that are expected during the ARP.[3]

$$X = \overline{MFP^R} + Stretch \quad [10b]$$

Since the X factor often includes *Stretch* it is sometimes said that index research has the goal of "calibrating" X.

Recall now from [6] that the trend in MFP^R can be decomposed into the trends in a cost efficiency index and an output differential. We can therefore logically decompose the MFP^R growth target of a price cap index into a cost efficiency growth target ("$\overline{MFP^C}$"), a stretch factor, and an output differential target.

$$X = \overline{MFP^C} + \overline{Output\ Differential} + Stretch. \quad [10c]$$

For energy distributors like CMP, the difference between the trends in *revenue-* and *cost-based* output indexes is usually similar to the trends in the average use of energy of residential and commercial ("R&C") customers. This is so because the volumes delivered to these customers are the chief drivers of *revenue* whereas the number of R&C customers is the chief driver of *cost*. This means that the X factor for the price cap index of an energy distributor is sensitive to the trend in average use. X factors for utilities experiencing declining average use should therefore typically be much lower than those for utilities experiencing brisk growth in average use. Growth in average use has slowed considerably in the northeast United States in recent years due to sluggish economic growth and the ramp up of demand side management ("DSM") programs.

[3] Mention here of the stretch factor option is not meant to imply that a positive stretch factor is warranted in all cases.

2.2.2 Revenue Cap Indexes

General Formulas

Mathematical theory can also be used to design revenue cap escalators that are based on rigorous input price and productivity research. Such escalators can be called revenue cap indexes ("RCIs"). Several approaches to the design of RCIs are consistent with index logic.

One approach is grounded in the following basic result of cost research:

$$\textit{trend Cost} = \textit{trend Input Prices} - \textit{trend Productivity}^C + \textit{trend Outputs}^C. \qquad [11a]$$

Cost growth is the difference between input price and cost efficiency growth plus the growth in operating scale, where growth in scale is measured by the same cost-based output index that is used to calculate productivity growth. This result provides the basis for a revenue cap escalator of general form

$$\textit{trend Revenue} = \textit{trend Input Prices} - X + \textit{trend Outputs}^C \qquad [11b]$$

where

$$X = \overline{MFP^C} + \textit{Stretch}. \qquad [11c]$$

Cost escalation formulas like [11a] have been used by the Essential Services Commission in the populous state of Victoria, Australia to establish multiyear O&M budgets for gas and electric distributors.

In gas and electric power distribution the number of customers served is an especially important output variable driving cost in the short and medium term. To the extent that this is true, $\textit{Outputs}^C$ can be reasonably approximated by growth in the number of customers served and there is no need for the complication of a multidimensional output index with cost elasticity weights. Relation [11a] can be restated as

$$\begin{aligned}\textit{trend Cost} \\ &= \textit{trend Input Prices} - (\textit{trend Customers} - \textit{trend Inputs}) + \textit{trend Customers} \\ &= \textit{trend Input Prices} - \textit{trend MFP}^N + \textit{trend Customers} \qquad [12a]\end{aligned}$$

where MFP^N is an MFP index that uses the number of customers to measure output.

Rearranging the terms of [12a] we obtain

$$\begin{aligned}\textit{trend Cost} - \textit{trend Customers} \\ &= \textit{trend (Cost/Customer)} = \textit{trend Input Prices} - \textit{trend MFP}^N. \qquad [12b]\end{aligned}$$

This provides the basis for the following revenue per customer ("RPC") index formula.

$$trend\ Revenue/Customer\ =\ trend\ Input\ Prices - X \qquad [12c]$$

where

$$X = \overline{MFP^N} + Stretch\ .$$

This general formula for the design of a revenue cap escalator is currently used in the ARPs of Gazifere, ATCO Gas, and AltaGas in Canada. The Regie de l'Energie in Quebec recently directed Gaz Metro to develop an ARP featuring revenue per customer indexes. Revenue per customer indexes have also been used by Southern California Gas and Enbridge Gas Distribution ("EGD"), the largest gas distributors in the US and Canada, respectively.

We can, alternatively, rearrange the terms of [12a] to obtain

$$trend\ Cost = trend\ Input\ Prices - (trend\ MFP^N - trend\ Customers) \qquad [12d]$$

This provides the basis for the following revenue cap formula, which has a consolidated X:

$$trend\ Revenue = trend\ Input\ Prices\ \text{-}\ X^{Consolidated} \qquad [12e]$$

where

$$X^{Consolidated} = \overline{MFP^N} + Stretch - trend\ Customers^{Forecasted}. \qquad [12f]$$

2.2.3 Choosing a Productivity Peer Group

Research on the productivity of other utilities can be used in several ways to calculate base productivity targets. Using the productivity trend of the entire industry to calibrate X is tantamount to simulating the outcome of competitive markets. A competitive market paradigm has broad appeal.

On the other hand, individual firms in competitive markets routinely experience windfall gains and losses. Our discussion in Section 2.1.2 of the sources of productivity growth implies that differences in the external business conditions driving productivity growth can cause utilities to have different productivity trends. For example, power distributors that are experiencing slow growth in the number of electric customers served are less likely to realize economies of scale than distributors that are experiencing rapid growth. Similarity in input prices is also important in reducing expected windfalls. There is thus considerable interest in methods for customizing X factors to reflect local business condition. The most common approach to date has been to calibrate the X factor for a utility using the input price and productivity trends of *similarly situated* (a/k/a "peer") utilities. The utilities are usually but not always chosen from the surrounding region.

2.2.4 Inflation Measure Issues

Index logic suggests that the inflation measure of an ARM should track the input price inflation of utilities. For incentive reasons, it is preferable that the inflation measure track the input price inflation of utilities generally rather than the prices actually paid by the subject utility.

Several issues in the choice of an inflation treatment must still be addressed. One is whether the inflation measure should be *expressly* designed to track utility industry input price inflation. There are several precedents for the use of utility-specific inflation measures in ARP rate escalation mechanisms. Such a measure was used in one of the world's first large-scale ARPs, which applied to U.S. railroads. Such measures have also been used in ARPs for Canadian railroads and for energy utilities in Alberta, California, and Ontario. The development of industry-specific input price indexes for energy utilities is facilitated by the availability of indexes for certain utility inputs from respected private vendors.

Notwithstanding such precedents, the majority of indexed-based ARMs approved worldwide do not feature industry-specific input price indexes. They instead feature measures of economy-wide (a/k/a "macroeconomic) price inflation. Gross domestic product price indexes ("GDPPI's") are most widely used for this purpose in North America. In the United States, the GDPPI is computed on a quarterly basis by the Bureau of Economic Analysis ("BEA") of the U.S. Department of Commerce. It is the federal government's featured measure of inflation in the prices of the economy's final goods and services. Final goods and services consist chiefly of consumer products. The GDPPI thus grows at a rate that is similar to that of the consumer price index ("CPI"). However, the GDPPI tracks inflation in a broader range of products that includes government services and capital equipment. The broader coverage makes the GDPPI less sensitive to volatility in prices of inputs, such as gasoline and foodstuffs, that have little impact on utility cost. The Maine PUC has approved the use of the GDPPI in previous PBR plans for CMP.

Macroeconomic inflation measures have some advantages over industry-specific measures in rate adjustment indexes. One is that they are available, at little or no cost, from government agencies. There is then no need to go through the chore of annually recalculating complex indexes or purchasing costly utility inflation data from private vendors. Another advantage is that customers are more familiar with macroeconomic price indexes (especially CPIs). The sizable task of designing an industry-specific price index during the proceeding that establishes the ARM is also sidestepped. The design of a capital price for such an index can be especially controversial.

When a macroeconomic inflation measure is used, the ARM must be calibrated in a special way if it is to reflect industry cost trends. Suppose, for example, that the inflation measure is a GDPPI. In that event we can restate the cost growth formula in [12d], for example, as

$$\begin{aligned} &\textit{trend Cost} = \textit{trend GDPPI} - [\textit{trend MFP}^{N} + \\ &\qquad (\textit{trend GDPPI} - \textit{trend Input Prices}) - \textit{trend Customers}] \end{aligned} \qquad [13]$$

It follows that an ARM with the GDPPI as the inflation measure can still conform to index logic provided that the X factor effectively corrects for any tendency of GDPPI growth to differ from industry input price growth.

Consider now that the GDPPI is a measure of *output* price inflation. Due to the broadly competitive structure of the U.S. economy, the long-run trend in the GDPPI is then the difference between the trends in input price and MFP indexes for the economy.

$$\textit{trend GDPPI} = \textit{trend Input Prices}^{Economy} - \textit{trend MFP}^{Economy}. \qquad [14]$$

Provided that the input price trends of the industry and the economy are similar, the growth trend of the GDPPI can thus be expected to be slower than that of the industry-specific input price index by the trend in the economy's MFP growth. In a period of rapid MFP growth this difference can be substantial. When the GDPPI is the inflation measure, the ARM therefore already tracks the input price and MFP trends of the economy. X factor calibration is warranted only to the extent that the input price and productivity trends of the utility industry differ from those of the economy.

Relations [13] and [14] can be combined to produce the following formula for a revenue cap escalator.

$$trend\ Revenue = trend\ GDPPI - \left[\begin{array}{l}\left(trend\ MFP^{Industry} - trend\ MFP^{Economy}\right) \\ + \left(trend\ Input\ Prices^{Economy} - trend\ Input\ Prices^{Industry}\right) + Stretch - growth\ Customers^{Forecasted}\end{array}\right] \quad [15]$$

This formula suggests that when the GDPPI is employed as the inflation measure, the revenue cap index can be calibrated to track industry cost trends when the X factor has a productivity differential and an input price differential. The productivity differential is the difference between the MFP trends of the industry and the economy. X will be larger (smaller), slowing (accelerating) revenue growth, to the extent that the industry MFP trend exceeds (is less than) the economy-wide MFP trend that is embodied in the GDPPI. The input price differential is the difference between the input price trends of the economy and the industry. X will be larger (smaller) to the extent that the input price trend of the economy is more (less) rapid than that of the industry.

The input price trends of a utility industry and the economy can differ for several reasons. One possibility is that prices in the industry grow at different rates than prices for the same inputs in the economy as a whole. For example, labor prices may grow more rapidly to the extent that utility workers have health care benefits that are better than the norm. Another possibility is that the prices of certain inputs grow at a different rate in some regions than they do on average throughout the economy. It is also noteworthy that the energy distribution industry has a different and more capital-intensive mix of inputs than the economy.

2.2.5 Revenue Decoupling

Revenue decoupling is an approach to utility rate regulation that decouples a utility's revenue (and thus its earnings) from its delivery volumes and other dimensions of system use. The most common approach to decoupling is the decoupling true up plan. In such a plan, a revenue decoupling mechanism ("RDM") typically ensures that the revenue ultimately received by the utility equals the revenue requirement ("RR") allowed revenue regardless of system use. Assuming for simplicity that decoupling occurs instantaneously, decoupling is typically achieved using an adjustment to "preliminary" revenue such as the following.

$$Revenue^{Final} = Revenue^{Preliminary} + (RR - Revenue^{Preliminary}). \qquad [16]$$

The revenue requirement in a decoupling true up plan is usually subject to escalation using some kind of ARM, and this usually takes the form of an allowed revenue cap. Since a utility's cost tends to grow, it will be compelled to file frequent rate cases under revenue decoupling in the absence of an ARM. The revenue cap indexes discussed in Section 2.2.2 are therefore useful escalators.

2.2.6 Long-Run Productivity Trends

An important issue in the design of a PCI is whether it should be designed to track short-run or long-run unit cost growth. An index designed to track short-run growth will also track the long-run growth trend if it is used over many years. An alternative approach is to design the index to track *only* long-run trends. Different approaches can, in principle, be taken for the input price and productivity components of the index.

Different treatments of input price and productivity growth are in most cases warranted when a PCI is calibrated to track the industry unit cost trend. The inflation measure should track *short-term* input price growth. The X factor, meanwhile, should generally reflect the long-run historical trend of MFP.

This general approach to PCI design has important advantages. The inflation measure exploits the greater availability of inflation data. Making the PCI responsive to short-term input price growth reduces utility operating risk without weakening performance incentives. Having X reflect the long-run industry MFP trend, meanwhile, sidesteps the need for more timely cost data and avoids the chore of annual MFP calculations.

To calculate the long-run productivity trend using indexes it is common to use a lengthy sample period. The sample period should be at least ten years. However, a period of more than twenty years may be unreflective of the current state of technological change. Moreover, consistent series of quality data are often unavailable for sample periods of longer length. The need for a long sample period is lessened to the extent that the output index does not assign a heavy weight to volatile output measures such as delivery volumes.

2.2.7 Dealing With Cost Exclusions

Many multiyear rate plans recover certain costs outside of the ARM. In PBR plans, costs that are targeted for exclusion are sometimes said to be "Y factored". The exclusions affect the research that is appropriate for calibrating the X factor. Suppose, for example, that costs of taxes and pensions are going to be Y factored under the ARP. These costs should then be excluded from the definition of cost that is used in the MFP research.

2.2.8 Data Quality

The quality of data used in index research has an important bearing on the relevance of results for the design of IR plans. Generally speaking, it is desirable to have publicly available data drawn from a standardized collection form such as those developed by government agencies. The best quality data of this kind are gathered by commercial venders that put in extra effort to ensure their quality and spread the cost of their work amongst numerous subscribers. Data quality also has a temporal dimension. It is customary for statistical cost research used in ARP design to include the latest data available.

2.3 Supplemental Capital Cost Funding

In many PBR plans supplemental revenue is available for special capital expenditures programs that cannot be funded by the index-based ARM. The most common form of supplemental capex funding is the capital cost "tracker". Key decisions to be made in the approval of such trackers are determination of the need for special treatment of capex, what types of projects should be afforded special treatment, and the timing of prudence reviews.

Out of the many North American regulators that have approved index-based PBR plans to date, only a few do not appear to have allowed a special ratemaking treatment for recovery of the cost of specific types of capital expenditures in any of their approved PBR plans for electric and gas utilities. Regulators in neighboring Vermont and

Massachusetts, for example, have approved special treatments of supplemental capex in PBR plans for at least one of their electric distributors. Here are additional details on some provisions for supplemental funding of capex in PBR plans of energy utilities in Alberta, British Columbia and Ontario in Canada and Massachusetts in the US.

2.3.1 Alberta

As part of its recent decision approving PBR plans for most provincial energy distributors, the AUC approved capital cost recovery mechanisms called capital trackers. The AUC established three eligibility criteria for tracker ratemaking treatment:

1) The project must be outside of the normal course of the company's ongoing operations.
2) Ordinarily the project must be for replacement of existing capital assets or undertaking the project must be required by an external party.
3) The project must require a material amount of funding.[4]

Utilities will be allowed to file capital tracker proposals on March 1st of each year for implementation in the following calendar year. Amounts that will be recovered under the capital tracker will reflect forecasted amounts with revenue requirements limited to the depreciation, taxes, and return on the incremental investment. There will be periodic true ups of forecasted to actual cost.

2.3.2 British Columbia

For both of the PBR plans of BC Gas (d/b/a FortisBC Energy), special treatments for capex requiring certificates of public convenience and necessity ("CPCNs") were outlined in the PBR settlements. In the first PBR plan, these projects were described as "capital projects which BC Gas foresees as being required within the Term, but have not been developed sufficiently…, or projects which are not foreseen but could be required".[5] Some examples of the former category were the Southern Crossing pipeline, automated meter reading, and various IT projects. An example of the latter category was the relocation of an urban transmission pipeline. The ratemaking treatment of CPCN

[4] Alberta Utilities Commission Decision 2012-237, p. 126.
[5] Consolidated Settlement Document, BC Gas Utility Ltd. 1998-2000 Revenue Requirements, page 9.

investments was similar in BC Gas' second PBR plan. The settlement generally excluded CPCNs for projects under $5 million and indicated that fewer CPCNs were expected during the second PBR plan.

2.3.3 Ontario

The settlement outlining the 2008-2012 Enbridge Gas index-based PBR plan also outlined a special treatment of capital in the form of a Y factor for capital required to connect electric gas-fired generating facilities to Enbridge's system. In order to qualify for Y factor treatment, the Ontario Energy Board would need to approve the investment in a "leave to construct" proceeding. This proceeding would also determine the budget that could be recovered through the Y factor after the project has been placed into service.

The index-based third generation PBR mechanism for Ontario's power distributors features two ratemaking treatments of capex outside of the index-based ARM. One is a treatment for capex that results from government mandates (in the case of Ontario, smart meters is an example). There is also an Incremental Capital Module that companies can request for specific non-governmentally mandated capital projects. The Board described the Incremental Capital Module as "reserved for unusual circumstances that are not captured as a Z-factor and where the distributor has no other options for meeting its capital requirements within the context of its financial capabilities underpinned by existing rates."[6] During the course of the third generation PBR term, the phrase "unusual circumstances" has been dropped from the criteria for Incremental Capital Module approval. Underspending will result in refunds to ratepayers.

There have over the years been 12 applications by 11 companies for an ICM. Of these, 9 have been approved, 2 were rejected, and 1 was withdrawn before a decision was rendered. The two largest distributors in Ontario, Hydro One Networks and Toronto Hydro Electric, have approved ICMs. ICMs have been used primarily for replacement capex that was out of the ordinary.

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[6] Ontario Energy Board Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors, p. 31. Filed September 17, 2008 in EB-2007-0673.

The fourth generation ARP for Ontario's power distributors is under development. It is expected to feature three ratemaking options: a British-style forecast-based approach to ARM design for distributors expecting chronically high capex, a price cap mechanism that would continue to feature the Incremental Capital Module as an option for distributors with lumpier capex needs, and a simplified price cap for distributors that anticipate a steady level of capex. A final decision on the fourth generation PBR for Ontario's power distributors is pending.

2.3.4 Massachusetts

Nstar Electric's PBR plan was outlined in a 2005 settlement between the company and intervenors which was approved by the Massachusetts Department of Telecommunications and Energy. The settlement committed Nstar to spend no less than $10 million in each year of the plan in addition to the cost presumed to be in base rates in each year of the plan in order to address safety-related issues. The revenue requirement associated with the investment, consisting of depreciation, return on investment, taxes, and O&M expenses, was recoverable in rates if the investment was determined to be prudent. A second special capital cost recovery mechanism for Nstar was approved in 2010 due to a change in state law requiring utilities in Massachusetts to file smart grid pilot programs by April 1, 2009. Nstar requested and received approval for recovery of 50% of its incremental expenditures outside of the indexing mechanism.

3. EMPIRICAL WORK FOR CMP

This section presents an overview of our index research to develop an ARM for the Company's new ARP. The discussion is largely non-technical. Additional details of the work are provided in Exhibit SUP-MNL-1.

3.1 Data

The primary source of the cost and quantity data used in the study was the Federal Energy Regulatory Commission ("FERC") Form 1. Major investor-owned electric utilities in the United States are required by law to file this form annually. Cost and quantity data reported on Form 1 must conform to the FERC's Uniform System of Accounts. Details of these accounts can be found in Title 18 of the Code of Federal Regulations.

FERC Form 1 data are processed by the Energy Information Administration ("EIA") of the U.S. Department of Energy. Selected Form 1 data were for many years published by the EIA.[7] More recently, the data have been available electronically in raw form from the FERC and in more processed forms from commercial vendors. FERC Form 1 data used in this study were obtained from one such vendor, SNL Financial.

Data were eligible for inclusion in the sample from all major investor-owned electric utilities in the Northeast that filed the Form 1 electronically in 2001 and that, together with any important predecessor companies, have reported the necessary data continuously since the 1960s.[8] To be included in the study the data were required, additionally, to be of good quality and plausible. Data from 14 companies in the upper Northeast and for 24 companies in the broad Northeast met these standards and were used in our indexing work. The data for these companies are the best available for rigorous work on input price and productivity trends to support the development of an X factor for CMP. The companies included in the indexing work are listed in Tables MNL-1 a and b.

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[7] This publication series had several titles over the years. A recent title is *Financial Statistics of Major U.S. Investor-Owned Electric Utilities.*

[8] We require capital cost data for decades prior to the sample period, as we explain further in Exhibit Sup-MNL-1 Section A.1.2.

Table MNL-1a

Companies in the Upper Northeast Productivity Peer Group

New England

Bangor Hydro-Electric	Massachusetts Electric
Central Maine Power	Narragansett Electric
Central Vermont Public Service	NSTAR Electric
Connecticut Light and Power	United Illuminating
Green Mountain Power	Western Massachusetts Electric
Maine Public Service	

Upstate New York

Central Hudson Gas & Electric	Orange & Rockland
New York State Electric & Gas	

Table MNL-1b

Companies in the Broad Northeast Productivity Peer Group

New England

Bangor Hydro-Electric

Central Maine Power

Central Vermont Public Service

Connecticut Light and Power

Green Mountain Power

Maine Public Service

Massachusetts Electric

Narragansett Electric

NSTAR Electric

United Illuminating

Western Massachusetts Electric

New York

Central Hudson Gas & Electric

New York State Electric & Gas

Orange & Rockland

Mid-Atlantic

Atlantic City Electric

Baltimore Gas and Electric

Duquesne Light

Jersey Central Power and Light

Metropolitan Edison

Pennsylvania Electric

Pennsylvania Power

Potomac Electric Power

Public Service Electric and Gas

West Penn Power

A noteworthy idiosyncrasy of the FERC Form 1 is that it requests data on retail power *sales* volumes but not data on the volumes of *unbundled distribution* services that might be provided under retail competition. Where retail competition exists, this complicates accurate calculation of trends in retail delivery volumes and customers. To address this issue we obtained our output data from Form EIA-861, the *Annual Electric Power Industry Report*. These data were also gathered by SNL Financial.

Other sources of data were also accessed in the research. These were used primarily to measure input price trends. The supplemental data sources were Whitman, Requardt & Associates; the Bureau of Economic Analysis ("BEA") of the U.S. Department of Commerce; Global Insight; and the BLS. The specific data drawn from these and the other sources mentioned are discussed further below.

3.2 Index Details

3.2.1 Scope

The indexes calculated in this study measured input price and productivity trends of utilities in their role as power distributors. The major tasks in a distribution operation are the local delivery of power and the reduction of its voltage from the level at which it is received from the transmission network.[9] Most power is delivered to end users at the voltage at which it is consumed. Power deliveries must be metered. Distributors also typically provide an array of customer services such as account, sales, and information services.

The costs considered in this study comprised operation and maintenance ("O&M") expenses and the cost of capital. Capital cost includes depreciation, taxes, and a return on plant value. Distributor cost was defined to include sensible shares of a utility's administrative and general ("A&G") expenses and its cost of general plant ownership.

The decomposition of capital cost into prices and quantities is required if we are to measure input price and quantity trends. The study used a service price approach to

[9] The term "distribution" in the Uniform System of Accounts corresponds most closely to local delivery service as here discussed.

effect this decomposition. Under this approach, the cost of capital is the product of a capital quantity index and an index of the price of capital services. This method has a solid basis in economics and has been widely used in scholarly research. The specific approach to capital cost measurement used in this study is designed to mirror the way that capital cost is counted under cost of service ("COS") regulation.

3.2.2 Index Construction

The growth (rate) of each MFP index calculated in this study is the difference between the growth rates of indexes of industry output and input quantity trends. The growth of the output quantity index for the industry is the growth in the total number of customers served. This specification is appropriate for the revenue cap index that the Company is proposing as an ARM.[10] The growth of the input quantity index is a weighted average of the growth in quantity subindexes for labor, materials and services, power distribution plant, and general plant. The growth of each input price index is a weighted average of the growth in price subindexes for these same input groups.

3.2.3 The Sample

The sample period was 2002-2011. The 2011 end date is the latest year for which all data that we use to calculate the input price and MFP indexes are currently available. The 2002 start date makes it possible to compute a ten year average growth rate and yet is recent enough to avoid most of the years of power industry restructuring that occurred in the Northeast. Appropriate adjustments to the cost data for the effects of restructuring were a source of controversy in CMP's last ARP proceeding. A longer sample period would also require "patching" FERC and EIA output data.

The utilities in the indexing sample were carefully chosen to mitigate controversy and follows principles advocated by Staff in the CMP's last ARP proceeding. Two regions were considered. The upper Northeast region was defined as New England and upper New York State. This region has been used for index research in past ARP proceedings in Maine and has been advocated by Bench Staff. Companies in this region face trends in input prices, output, and other business conditions affecting unit cost

[10] In the productivity index we used in CMP's last ARP filing, the output index was revenue-weighted and placed a heavy weight on delivery volumes because the Company was proposing a price cap index.

growth that are similar to those facing CMP. We also considered a broad Northeast region that includes, additionally, utilities in the District of Columbia, Maryland, Pennsylvania, and New Jersey.

3.3 Index Results

3.3.1 MFP

Tables MNL-2a and 2b and Figure MNL-1 report key results of our MFP research. Findings are presented for the 2002-2011 period for the MFP index and the component output and input quantity indexes. It can be seen that over the full sample period the annual average growth rate in the MFP of sampled power distributors in the upper Northeast was about **0.56%**.[11] Output quantity growth averaged a **0.65%** pace annually while input quantity growth averaged just **0.09%** annually. Output growth in the region has slowed appreciably during the years of CMP's current ARP.

Table MNL-2a also reports the trends in the MFP index for the U.S. private business sector over the 2002-2011 period for which data are available. This index is calculated by the BLS. It can be seen that its **1.11%** average annual growth rate was very similar to the trend in the MFP index for Northeast power distributors. A productivity differential based on the difference between the growth trends of these indexes is **-0.55%**.

Table MNL-2b reports that the MFP growth of sampled utilities in the broad Northeast utilities averaged **1.06%** annually. Output quantity growth averaging **0.62%** annually outpaced input quantity growth that declined by **0.44%** on average. The resultant productivity differential was **-0.05%**.

Table MNL-3 reports MFP results for CMP over the 2002-2011 period. It can be seen that productivity growth averaged **1.68%** per annum, well above the trend for the peer group. Output growth averaging **0.96%** was modestly more rapid than that of the peer groups. Input quantities declined by **0.72%** each year on average. Capital productivity grew more rapidly than O&M productivity. Growth in capital productivity

[11] All growth trends noted in this report were computed logarithmically.

Table MNL-2a

Calculating the Productivity Differential: Upper Northeast

	Productivity Growth				Productivity Differential
	Northeast Power Distributors			U.S. Private Business Sector	
	Output Quantity	Input Quantity	MFP	MFP[1]	
			[A]	[B]	[A] - [B]
2002	0.88%	1.06%	-0.18%	2.40%	-2.58%
2003	1.03%	0.50%	0.53%	2.70%	-2.17%
2004	0.80%	-1.63%	2.42%	2.40%	0.02%
2005	1.00%	0.96%	0.04%	1.00%	-0.96%
2006	0.88%	0.75%	0.14%	0.40%	-0.26%
2007	1.18%	-0.59%	1.77%	0.30%	1.47%
2008	-0.07%	0.73%	-0.80%	-1.20%	0.40%
2009	0.07%	0.58%	-0.51%	-0.10%	-0.41%
2010	0.26%	1.54%	-1.28%	2.50%	-3.78%
2011	0.48%	-3.00%	3.48%	0.70%	2.78%
Average Annual Growth Rate 2002-2011	**0.65%**	**0.09%**	**0.56%**	**1.11%**	**-0.55%**

[1]Source: U.S. Bureau of Labor Statistics

Table MNL-2b

Calculating the Productivity Differential: Broad Northeast

	Productivity Growth				Productivity Differential
	Northeast Power Distributors			U.S. Private Business Sector MFP[1]	
	Output Quantity	Input Quantity	MFP		
			[A]	[B]	[A] - [B]
2002	0.77%	-0.85%	1.61%	2.40%	-0.79%
2003	0.93%	2.62%	-1.68%	2.70%	-4.38%
2004	0.77%	-4.70%	5.46%	2.40%	3.06%
2005	0.96%	0.43%	0.54%	1.00%	-0.46%
2006	0.91%	-0.20%	1.11%	0.40%	0.71%
2007	0.90%	0.72%	0.18%	0.30%	-0.12%
2008	0.15%	-0.56%	0.71%	-1.20%	1.91%
2009	0.19%	-1.69%	1.89%	-0.10%	1.99%
2010	0.33%	1.52%	-1.19%	2.50%	-3.69%
2011	0.32%	-1.65%	1.97%	0.70%	1.27%
Average Annual Growth Rate 2002-2011	**0.62%**	**-0.44%**	**1.06%**	**1.11%**	**-0.05%**

[1]Source: U.S. Bureau of Labor Statistics

Figure MNL-1

MFP TREND OF UPPER NORTHEAST POWER DISTRIBUTORS

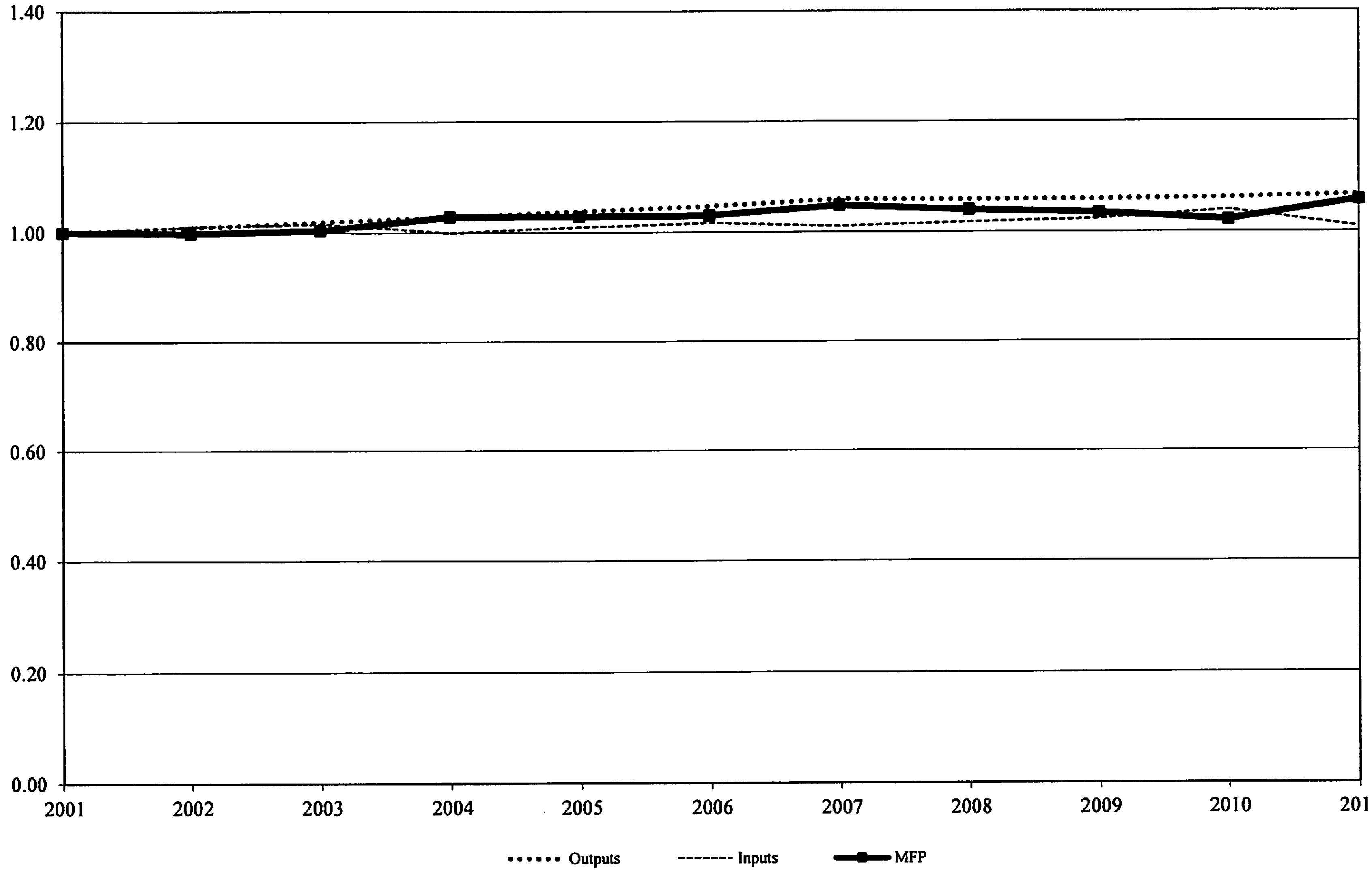


Table MNL-3

Output, Input, and Productivity Trends of Central Maine Power

	Output Quantity [A]	Input Quantity [B]	MFP [A-B]
Year			
2002	1.51%	-0.78%	2.29%
2003	1.39%	-1.46%	2.85%
2004	1.47%	-3.93%	5.40%
2005	1.45%	-2.25%	3.70%
2006	1.35%	2.52%	-1.17%
2007	1.39%	-0.63%	2.02%
2008	0.10%	0.17%	-0.08%
2009	0.19%	6.04%	-5.85%
2010	0.43%	-9.33%	9.77%
2011	0.29%	2.44%	-2.15%
Average Annual Growth Rate			
2002-2011	**0.96%**	**-0.72%**	**1.68%**

Data Sources: FERC Form 1 (power distributor cost and bond yield), Form EIA-861 (customers), US Bureau of Labor Statistics (labor price indexes), Global Insight (power distributor material and service price indexes), Whitman, Requardt & Associates (power distribution construction cost index), and Regulatory Research Associates (electric utility allowed ROE) was especially brisk from 2002 to 2006 but has since slowed, and turned negative in 2011.

3.3.2 Input Prices

Table MNL-4 and Figure MNL-2 report key findings of our input price research. From 2002 to 2011, input prices facing sampled upper Northeast distributors were found to average about **3.55%** average annual growth. The input prices facing broad Northeast distributors were found to average **3.44%** annual growth.

An input price index for the U.S. economy is not expressly computed by the federal government, so index logic was used to calculate the economy's input price trend using other government indexes. To the extent that the economy earns a competitive return, the long-term trend in its *input* prices is the sum of the trends in its *output* prices and its TFP. Using GDPPI as the output price index and the MFP index for the U.S. private business sector to measure of the economy's TFP growth, the trend in the economy's input prices can be calculated.

From 2002 to 2011, input prices in the U.S. economy are estimated to have grown at about a **3.20%** average annual rate. This is similar to but a little less than the growth in the input prices facing northeast power distributors. The input price differential resulting from this analysis is thus about **-0.35%** for the upper Northeast and **-0.24%** for the broad Northeast.

3.4 K Factor

CMP increased its plant additions substantially in 2011 in an effort to accelerate modernization of its distribution system. The company expects its distribution capex to continue at higher levels during the term of the proposed ARP. We have developed an adjustment to X, which we call the K factor, which would provide CMP with some supplemental revenue for its construction program. The K factor is based on statistical research on the cost of power distributors and therefore will not weaken CMP's performance incentives or require a review of the Company's capex plan.

The basic idea is to compute how the productivity trends of utilities that started the sample period with capital inputs similar to CMP's recent level differed from the

Table MNL-4

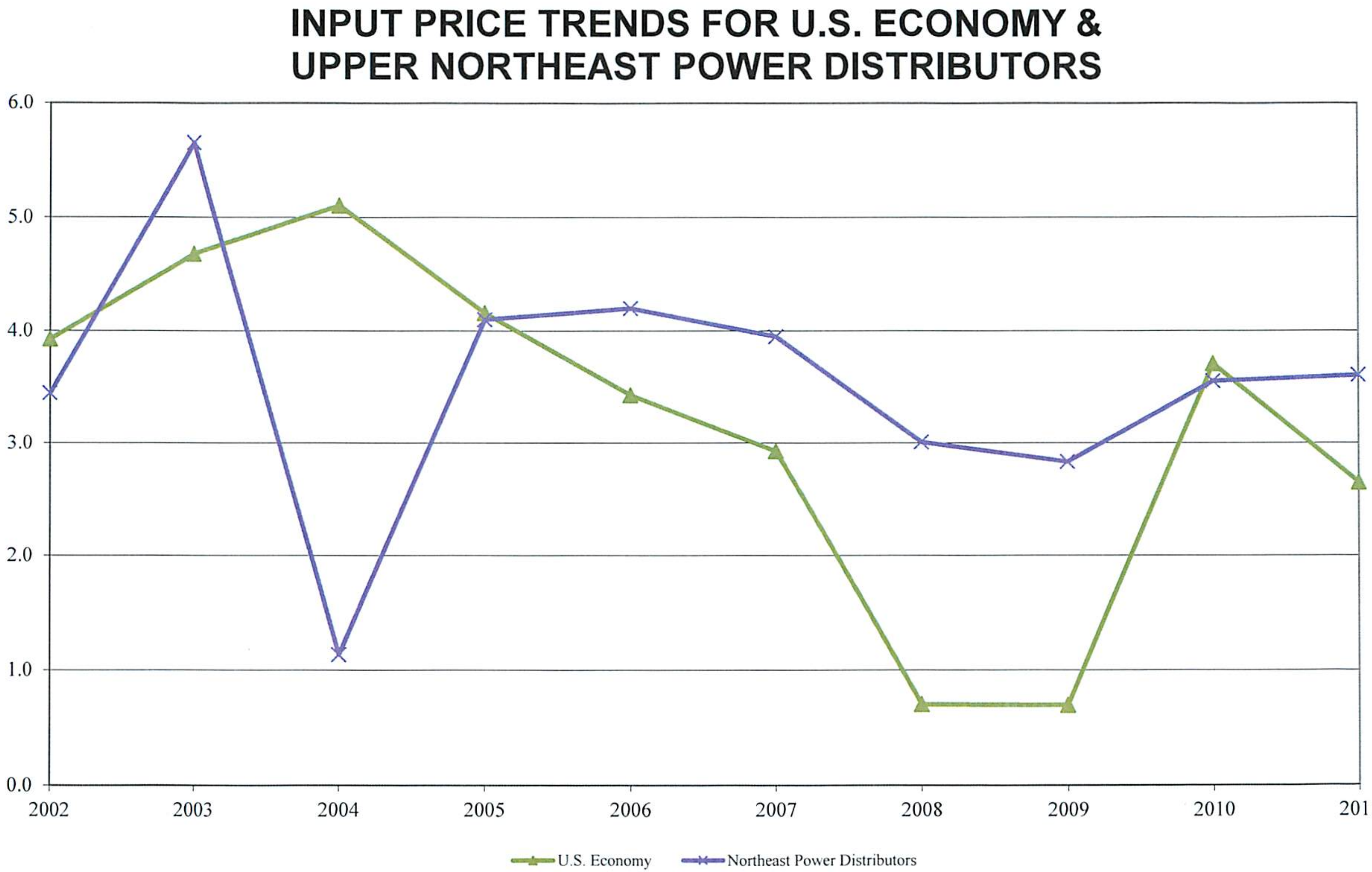
Calculating the Input Price Differential

	Input Price Trends					Input Price Differential	
	United States			Power Distributors			
	GDP-PI[1]	MFP[2]	Implied IPI	Upper Northeast	Broad Northeast	Upper Northeast	Broad Northeast
	[A]	[B]	[C=A+B]	[D1]	[D2]	[E=C-D1]	[E=C-D2]
	(%)	(%)	(%)	(%)	(%)	(%)	(%)
2002	1.53	2.40	3.93	3.44	3.17	0.48	0.76
2003	1.98	2.70	4.68	5.65	4.19	-0.97	0.48
2004	2.70	2.40	5.10	1.13	1.61	3.97	3.49
2005	3.16	1.00	4.16	4.10	3.98	0.06	0.17
2006	3.03	0.40	3.43	4.20	3.93	-0.77	-0.50
2007	2.63	0.30	2.93	3.95	3.18	-1.02	-0.25
2008	1.90	-1.20	0.70	3.01	3.19	-2.30	-2.49
2009	0.80	-0.10	0.70	2.83	3.94	-2.14	-3.24
2010	1.21	2.50	3.71	3.55	3.16	0.15	0.55
2011	1.95	0.70	2.65	3.60	4.06	-0.96	-1.41
Average Annual Growth Rate 2002-2011	**2.09%**	**1.11%**	**3.20%**	**3.55%**	**3.44%**	**-0.35%**	**-0.24%**

[1] Gross Domestic Product Price Index calculated by the BEA.

[2] Multifactor productivity for the U.S. private business sector calculated by the BLS.

Figure MNL-2


INPUT PRICE TRENDS FOR U.S. ECONOMY & UPPER NORTHEAST POWER DISTRIBUTORS
6.0
5.0
4.0
3.0
2.0
1.0
0.0
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
U.S. Economy
Northeast Power Distributors

average productivity trend of utilities in a region. This research involves a multistage process. We first developed an econometric capital cost benchmarking model, the parameters of which were estimated using cost and other operating data from a national sample of US power distributors. In 2011, the most recent year of our sample period, CMP's capital cost was about 21% below the model's predictions. This was one of the better capital cost containment performances in the US sample.

The second step in the analysis was to consider how the average MFP growth of a peer group of utilities with a capital cost score close to **21%** on average *in 2001*, at the start of the sample period, differed from the average MFP growth of all utilities. This exercise was conducted for each Northeast region. Theory suggests that these utilities might need to rebuild their capital stock and in the process experience slow productivity growth. To preserve strong performance incentives for CMP it is excluded from the low-capital peer group.

The sampled utilities in the upper Northeast averaged **0.56%** annual MFP growth, as previously noted. The peer group of utilities with initially low capital inputs averaged, in contrast, **-0.06%** productivity growth. The resultant productivity growth differential was **-0.63%**. This is the indicated K factor for this region.

As for the broad Northeast, the sampled utilities averaged **1.06%** annual MFP growth, as previously noted. The peer group of utilities with initially low capital inputs averaged, in contrast, **0.70%** productivity growth. The resultant productivity growth differential was **-0.36%**.

3.5 Stretch Factor

The stretch factor term of an X factor should reflect the expectation of improved performance under the ARP. This depends on the company's operating efficiency at the start of the plan, and on how the performance incentives generated by the ARP compare to those in force for sampled utilities during the index sample period. CMP's impressive productivity growth under previous ARPs should have brought it to a level of performance that is at least average for the industry, and possibly better.

Performance incentives under the ARP are strengthened by the proposed five-year term but weakened by the proposed sharing of surplus earnings. Meanwhile, rate cases were filed on average every 4.8 years by utilities in the upper Northeast during the sample period and every 5.9 years by utilities in the broad Northeast. In the broad Northeast most utilities were not subject to earnings sharing mechanisms.

The productivity trend of the sampled utilities should therefore reflect the impact of performance incentives that were as strong or, in the case of the broad Northeast, actually stronger than those which CMP will likely face. For an average cost performer, no acceleration in MFP growth could be expected from operating under the ARP proposed by CMP. Based on this reasoning, together with the observation that CMP has just experienced a period of rapid MFP growth unlikely to be replicated, an appropriate stretch factor for CMP should be 0.00%.

3.6 Indicated X Factor

Assuming the use of GDPPI as the inflation measure, our research using upper Northeast data suggests that the consolidated X factor for a revenue cap index for CMP is **-1.90%**. This is the sum of a **-0.55%** productivity differential, a **-0.35%** input price differential, a **-0.63%** K factor, a stretch factor of **0.00%**, and a **-0.37%** offset for CMP's forecasted customer growth.

Using data for the broad Northeast, our research suggests that the consolidated X factor for a revenue cap index for CMP is **-1.02%**. This is the sum of a **-0.05%** productivity differential, a **-0.24%** input price differential, a **-0.36%** K factor, a stretch factor of **0.00%**, and a **-0.37%** offset for customer growth.

EXHIBIT SUP-MNL-1

This exhibit contains additional details of our new price and productivity research for CMP. Section A.1 addresses our calculation of distribution cost. Sections A.2 and A.3 address the input price and input quantity indexes, respectively. Section A.4 discusses the econometric capital cost model.

A.1 Distribution Cost

A.1.1 Total Cost

The total cost of power distribution considered in the study was the sum of applicable O&M expenses and capital costs. Applicable O&M expenses included those for distribution, sales, and customer accounts other than those for uncollectible bills, plus a sensible share of the company's total A&G expenses. Uncollectible bill expenses were excluded because they exhibited a rising trend, due to weak economic growth, that is likely to be atypical of the long-term trend. Customer service and information expenses were excluded because they have been increasingly dominated by DSM expenses, which would be subject to separate ratemaking treatment under the ARP. Assigned capital cost consisted of the cost of distribution plant and a sensible share of the cost of general plant.

A&G expenses are O&M expenses that are not readily assigned directly to particular operating functions under the Uniform System of Accounts. They include expenses incurred for pensions and other benefits, injuries and damages; property insurance, regulatory proceedings, stockholder relations, and general advertising of the utility; the salaries and wages of A&G employees; and the expenses for office supplies, rental services, outside services, and maintenance activities that are needed for general administration.

General plant is plant that is not directly assigned to particular operating functions in the Uniform System of Accounts. Certain structures and improvements (*e.g.*, office buildings), communications equipment, office furniture and equipment, and transportation equipment account for the bulk of general plant value. Other general plant categories in the Uniform System of Accounts include tools, shop, and garage equipment, laboratory equipment, miscellaneous power-operated equipment, land and land rights, and stores equipment.

A.1.2 Dealing with Capital in Productivity Research

Introduction

Trends in the price and quantity of capital play a critical role in measurement of trends in the MFP and prices of utility base rate inputs. Summary input price and quantity indexes are, after all, cost-weighted, and capital typically accounts for half or more of total cost. A practical means must thus be found to calculate capital cost, and to decompose it into consistent price and quantity indexes such that

$$trend\ Cost^{Capital} = trend\ Price^{Capital} + trend\ Quantity^{Capital}. \qquad [A1]$$

Capital prices can be volatile. Disagreement over capital price trends has made calculation of the input price differential a controversial issue in some North American ARP proceedings.

The capital quantity index is, effectively, an index of the trend in the real (inflation-adjusted) cost of depreciated plant. Indexes of construction costs are commonly used to measure plant-addition price trends in utility productivity research. The rate base of an energy distributor tends to grow over time due to system expansion and inflation of construction prices. However, capital quantity indexes of energy distributors sometimes display a negative trend.

The capital price index measures the trend in the cost of owning a unit of capital. It is sometimes called a "rental" or "service" price index because, in a competitive rental market, the trend in prices tends to reflect the trend in the unit cost of capital ownership. The monthly charge for an automobile lease, for instance, should reflect the monthly cost to the lessor of owning the automobile.

The components of capital cost include depreciation and the return on investment. Capital cost thus depends on construction prices, depreciation rates, and the rate of return on capital. A capital service price index should reflect the trends in these conditions.

A utility's rate of return reflects returns on various kinds of investments, and rates of returns on different kinds of investments can differ markedly. Yields on long-term bonds, for instance, soared on the occasion of the second oil price shock and then fell gradually for many years. Returns on equity have displayed a less pronounced downward trend.

Utilities have diverse methods for calculating depreciation expenses. In calculating capital costs and quantities, it is therefore desirable in productivity research to rely chiefly on the companies for the value of plant *additions* and then use a standardized depreciation treatment to construct a capital quantity index. Since the quantity of capital on hand may involve plant added thirty to fifty years ago, data on plant additions for many years in the past are needed. For some of the earliest years for which plant addition data are needed, however, the data are often unavailable and the plant additions must be imputed using aggregate plant value data and construction price indexes for a certain early "benchmark" year.

Three practical methods have been developed for calculating capital costs that can be decomposed into input price and quantity indexes: geometric decay, one hoss shay, and cost of service. All have been used over the years in CMP's productivity evidence. The choice of a capital costing methodology is an important issue in X factor calibration.

Geometric Decay

The critical assumptions of the geometric decay ("GD") approach are twofold.

- Utility plant is valued in *current* dollars, so that plant values reflect the cost of asset replacement.
- Plant depreciates at a constant rate.

Both assumptions differ from those used in computing capital cost in North American utility rate regulation.

Current valuation of plant means that owners profit from capital gains. If the value of assets is rising, the *net* cost of plant ownership can be appreciably less than the *gross* due to capital gains. The capital service price should then reflect the expected net cost of owning a unit of plant.

Abstracting from taxes, here is a GD capital service price that corresponds to these assumptions.

$$WKS_t = d \cdot WKA_t + WKA_{t-1} \cdot r - E(WKA_t - WKA_{t-1}). \qquad [A2]$$

Here the term d is the (constant) rate of depreciation. The term WKA_t is the current price of a unit of utility plant. In a competitive market for construction services this would equal, in the long run, the cost to construct a unit of plant. Accordingly, the trend in WKA_t is commonly measured using construction cost indexes. The term r_t is the cost of obtaining a dollar of funds in capital markets.

Examining equation [A2] it can be seen to contain three groups of terms. The first corresponds to the cost of depreciation, the second to the opportunity cost of capital, and the third term to expected capital gains. The last two terms can be consolidated into one term that represents the expected real (inflation-adjusted) rate of return on capital ownership. The service price can then be restated as

$$WKS_{jt} = d \cdot WKA_{j,t} + WKA_{j,t-1} \cdot E\left[r_t - \frac{(WKA_{j,t} - WKA_{j,t-1})}{WKA_{j,t-1}}\right]. \qquad [A3]$$

The term in brackets is the real rate of return.

While GD service price equations are mathematically elegant, they have serious practical implementation problems in an X factor calibration exercise. One is that there is no established method of modeling the expected growth of the real rate of return. Another problem is the unusual instability of GD service prices, which stems from the fact that the rate of return does not always rise in tandem with asset price (or construction cost) inflation. The real rate of return is, in practice, considerably more volatile than the nominal rate of return that matters in COS regulation. In recent years, for example, it has sometimes been negative as a falling rate of return coincided with rapid growth in construction costs.

The instability of the capital service price using the GD approach to capital costing means that it must be smoothed before its trend can be calculated. Different approaches to smoothing have materially different effects on trend calculations. The proper approach to smoothing can be a source of dispute, and smoothing does not always eliminate service price volatility.

The GD method has nonetheless been widely used in productivity research. Despite the controversy that can arise over input price differentials, it has been used several times in index research intended to calibrate X factors. One example was the X factor testimony of Dr. Lowry in CMP's first price cap filing. This approach was also used by Dr. Phil Schoech in research for Bench Staff during the last ARP proceeding.

One Hoss Shay

The one hoss shay approach to capital costing assumes that plant does not depreciate gradually but, rather, all at once as the asset reaches the end of its service life. The plant is valued in current dollars, so that capital gains and capital price volatility are once again issues. Although the assumptions underlying the one hoss shay method are very different from those used to compute capital cost in utility regulation, the method has been used occasionally in research intended to calibrate utility X factors. An example is the research supporting the testimony of Dr. Jeff Makholm in CMP's second price cap filing.

Cost of Service

This study features a cost of service approach to capital costing. This approach has been developed by PEG Research to better approximate the way that capital cost is calculated in utility regulation. It is based on the assumption of straight line depreciation and the historic (a/k/a "book") valuation of plant. There are no capital gains from asset appreciation. Because of historical valuation, the capital price is a function not simply of the *current* construction price but, rather, of a weighted average of current and past values. This weighting, together with the exclusion of capital gains, stabilizes the capital price index substantially, thus reducing potential controversy surrounding the inflation differential in an ARP proceeding.

The intuition for taking a weighted average of past construction cost index values is that construction cost inflation drives rate base growth in a particular way. The cost of constructing plant that is, for example, two, four, and twenty years old is higher this year than was the cost of construction two, four, and twenty years ago last year. The weight for construction cost of a given vintage is larger the larger is its representation in the value of the rate base. Weights tend to be larger for more recent years than for earlier years because construction costs were higher and there has been less cumulative depreciation.

We have used our COS method in studies presented in testimony for Atlantic City Electric, Central Maine Power, Central Vermont Public Service, the Consumers' Coalition of Alberta, Delmarva Power, Fitchburg Gas & Electric, the Ontario Energy Board, Potomac Electric Power, Public Service of Colorado, Gaz Metro, and the Gaz

Metro Task Force. The productivity growth target in the current price cap plans of Ontario power distributors is based on productivity research that used COS capital costing. The methodology was also used to set an X factor for the revenue cap index of Central Vermont Public Service.

Note, additionally that Professor Alfred Kahn developed an approach to X factor calibration which is implicitly based on cost of service capital cost measurement. The results of Kahn's work found favor with the FERC in the establishment of an ARP for oil pipelines. Christensen Associates has occasionally used an approach to capital costing with COS attributes in its telecommunications productivity research.

Here is the mathematical derivation of our COS formulas. For each year, t, of the sample period let

ck_t = Total non-tax cost of capital

$ck_t^{Opportunity}$ = Opportunity cost of capital

$ck_t^{Depreciation}$ = Depreciation cost of capital

VK_{t-s}^{add} = Gross value of plant installed in year t-s

WKA_{t-s} = Unit cost of plant installed in year t-s (the "price" of capital assets)

a_{t-s} = Quantity of plant additions in year $t-s = VK_{t-s}^{add} / WKA_{t-s}$

xk_t = Total quantity of plant available for use and that results in year t costs

xk_t^{t-s} = Quantity of plant available for use in year t that remains from plant additions in year t-s

VK_t = Total value of plant at the end of last year

N = Service life of utility plant

r_t = Rate of return (cost of funds)

WKS_t = Price of capital service

A few assumptions that are made for convenience in the derivation to follow:

(1) All kinds of plant have the same service life N.

(2) Full annual depreciation and opportunity cost are incurred in year t on the amount of plant remaining at the end of year t-1, as well as on any plant added in year t.

(3) The ARM is not designed to recover changes in taxes.

Consider, now, that the non-tax cost of capital under cost of service regulation is the sum of depreciation and the opportunity cost paid out to bond and equity holders.

$$ck_t = ck_t^{\,opportunity} + ck_t^{\,depreciation}$$

Assuming straight line depreciation and book valuation of utility plant,

$$\begin{aligned} ck_t &= \sum_{s=0}^{N-1} \left(WKA_{t-s} \cdot xk_t^{t-s}\right) \cdot r_t + \sum_{s=0}^{N-1} WKA_{t-s} \left(1/N\right) \cdot a_{t-s} \\ &= xk_t \cdot \sum_{s=0}^{N-1} \left(\frac{xk_t^{t-s}}{xk_t} \cdot WKA_{t-s} \right) \cdot r_t + xk_t \cdot \sum_{s=0}^{N-1} WKA_{t-s} \cdot \frac{\left(1/N\right) \cdot a_{t-s}}{xk_{t-1}}. \end{aligned} \qquad [A4]$$

where, as per assumption 2 above,

$$xk_t = \sum_{s=0}^{N-1} xk_t^{t-s}. \qquad [A5]$$

Under straight line depreciation we posit that in the interval $\left[(t-(N-1)),(t-1)\right]$,

$$xk_t^{t-s} = \frac{N-s}{N} \cdot a_{t-s}. \qquad [A6]$$

Combining [A5] and [A6] we obtain a capital quantity index that is a perpetual inventory equation.

$$xk_t = \sum_{s=0}^{N-1} \frac{N-s}{N} \cdot a_{t-s}. \qquad [A7]$$

The size of the addition in year t-s of the interval (t-1, t-N) can then be expressed as

$$a_{t-s} = \frac{N}{N-s} \cdot xk_t^{t-s}. \qquad [A8]$$

Relations [A4] and [A8] together imply that

$$\begin{aligned} ck_t &= xk_t \cdot \sum_{s=0}^{N-1} \left(\frac{xk_{t-1}^{t-s}}{xk_t} \cdot WKA_{t-s} \right) \cdot r_t + xk_t \cdot \sum_{s=0}^{N-1} \frac{xk_t^{t-s}}{xk_{t-1}} \cdot WKA_{t-s} \cdot \frac{1}{N-s} \qquad [A9] \\ &= xk_t \cdot WKS_t. \end{aligned}$$

Here

$$WKS_t = \sum_{s=0}^{N-1} \frac{xk_{t-1}^{t-s}}{xk_t} \cdot WKA_{t-s} \cdot r_t + \sum_{s=0}^{N-1} \frac{xk_t^{t-s}}{xk_t} \cdot WKA_{t-s} \cdot \frac{1}{N-s}. \qquad [A10]$$

Relation [A10] reveals that the cost of capital under COS regulation can be decomposed into a capital price index and a capital quantity index. The capital service price in a given year reflects a weighted average of the capital asset prices in the N most recent years (including the current year). The weight for each year, t-s, is the estimated share, in the total amount of plant that contributes to cost, of plant remaining from additions in that year. This share will be larger the more recent the plant addition year and the larger were the plant additions made in that year. The average asset price rises over time as the price for each of the N years is replaced with the higher price for the following year. It will reflect inflation that occurred in numerous past years as well as current inflation. Note also that the depreciation rate varies with the age of the plant. For example, the depreciation rate in the last year of an asset's service life is 100%.[12]

Implementation Relations [A7] and [A10] were calculated for each sampled utility for two categories of assets: distribution plant and general plant. In these calculations, regional Handy-Whitman indexes of construction costs in the northeastern states were used as the asset price indexes.[13] In the distribution index the value of N was set at 44, our computation of the average service life of CMP distribution assets. The value of N for general plant was set at 12 years. The values for gross plant additions VK_{t-s}^{add} in the years 1965-2011 were drawn from the FERC Form 1. Values for earlier years were imputed using data on the net value of plant in 1964 and the construction cost index values for those years.

The calculation of [A10] requires, in addition, an estimate of the rate of return trend.[14] We employed a weighted average of the returns on four kinds of assets: an ROE

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[12] Recall that the depreciation rate is constant under the geometric decay approach to capital costing.

[13] These data are reported in the *Handy-Whitman Index of Public Utility Construction Costs*, a publication of Whitman, Requardt and Associates.

[14] This calculation was made solely for the purpose of measuring input price and productivity *trends* and does not prescribe an appropriate Rate of Return *level* for the Company in this

and the yields on Baa-rated corporate long bonds, ten-year treasury notes, and commercial paper. The ROE is the average of approved ROEs for a large sample of U.S. utilities. The ROE data were compiled by the Regulatory Research Associates unit of SNL Financial. For the bond yields, we computed 10 year averages of bond yields reported by Moodys Investor Services.[15] The weights for the three rates of return reflect the mix of funding sources employed recently by CMP.

A.2 Input Price Indexes

The growth rate of a summary input price index is calculated using a formula that involves subindexes measuring growth in the prices of various kinds of inputs. Major decisions in the design of such indexes include their form and the choice of input categories and price subindexes.

A.2.1 Index Form

The summary input price index used in this study is of Tornqvist form.[16] Its growth rate is a weighted average of the growth rates of input price subindexes. Each growth rate is calculated as the natural logarithm of the ratio of the subindex values in successive years. The average shares of each input in the applicable total cost of distributors during the two years are the weights.

A.2.2 Input Price Subindexes and Costs

Applicable total cost was divided for purposes of input price trend calculations into four input categories: distribution plant, general plant, labor services, and other O&M inputs. The cost of labor was defined for this purpose as the sum of salaries and wages and a sensible share of expenses for pensions and other employee benefits. The cost of other O&M inputs was defined as applicable O&M expenses net of these labor

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proceeding. For example, the yield on ten year U.S. treasury notes is well below the yield that CMP would pay on bonds of similar duration.

[15] As used here, the term long bonds refers to debt securities with maturities of more than ten years. In calculating the trend in the rates of return, we used the trends in Baa corporate bonds and in 10 year treasury notes to measure the trends in the typical yields faced by power distributors for long- and short-term debt, respectively.

[16] For seminal discussions of this index form see Tornqvist (1936) and Theil (1965).

costs. The latter input category comprises a diverse set of inputs that includes materials, outsourced services, and leased equipment and real estate. The cost share for capital included taxes.

The price subindex for labor was the ratio of labor expenses to the labor quantity index. The price subindex for materials and services was calculated from detailed electric utility material and service ("M&S") price indexes prepared by Global Insight. The price subindexes for distribution and general plant were capital service price indexes. The capital price subindexes used in the trend comparisons did not include the term for taxes. Tables MNL-5 a and b and Figure MNL-3 present additional information on the power distribution input price trends of sampled utilities.

A.3 Input Quantity Indexes

The growth rate of a summary input quantity index is calculated by a formula. The formula involves subindexes measuring growth in the amounts of various kinds of inputs used. Major decisions in the design of such indexes include their form and the choice of input categories and quantity subindexes.

A.3.1 Index Form

The input quantity index used in this study is of Tornqvist form. The growth rate of the index is a weighted average of the growth rates of the quantity subindexes. Each growth rate is calculated as the natural logarithm of the ratio of the quantities in successive years. The average shares of each input in the applicable total distributor cost of sampled utilities during these two years are the weights.

A.3.2 Input Quantity Subindexes and Costs

Applicable total cost was divided into the same four input categories used to develop the input price index: distribution plant, general plant, labor services, and other O&M inputs. The quantity subindex for labor was the ratio of salary and wage expenses to a labor price index for the northeast U.S.[17] The growth rate of the labor price index in this application

[17] Utilities no longer report on their FERC Form 1 the number of workers that they employ.

Table MNL-5a

Input Price Trends of Upper Northeast Power Distributors

	Input Price Growth Rates				Summary Input Price Trend
	Distribution Capital	General Capital	Labor O&M[1]	Materials & Services[2]	
2002	2.5%	3.2%	4.7%	1.8%	3.44%
2003	2.8%	3.9%	4.2%	2.8%	5.65%
2004	2.8%	3.4%	5.7%	3.9%	1.13%
2005	3.2%	2.5%	5.2%	4.5%	4.10%
2006	3.8%	2.9%	10.2%	4.7%	4.20%
2007	3.7%	3.7%	-4.3%	3.9%	3.95%
2008	3.5%	4.1%	3.1%	5.2%	3.01%
2009	3.4%	2.2%	3.1%	0.3%	2.83%
2010	3.5%	1.2%	5.5%	2.7%	3.55%
2011	3.2%	3.0%	3.4%	3.6%	3.60%
Average Annual Growth Rate 2002-2011	**3.24%**	**3.02%**	**4.08%**	**3.32%**	**3.55%**

[1] Labor trend index is calculated residually for each company as the ratio of labor O&M expenses to the O&M labor quantity index.

[2] M&S price index constructed from detailed price indexes for power distribution utility materials and services prepared by Global Insight for its Power Planner information service.

Table MNL-5b

Input Price Trends of Broad Northeast Power Distributors

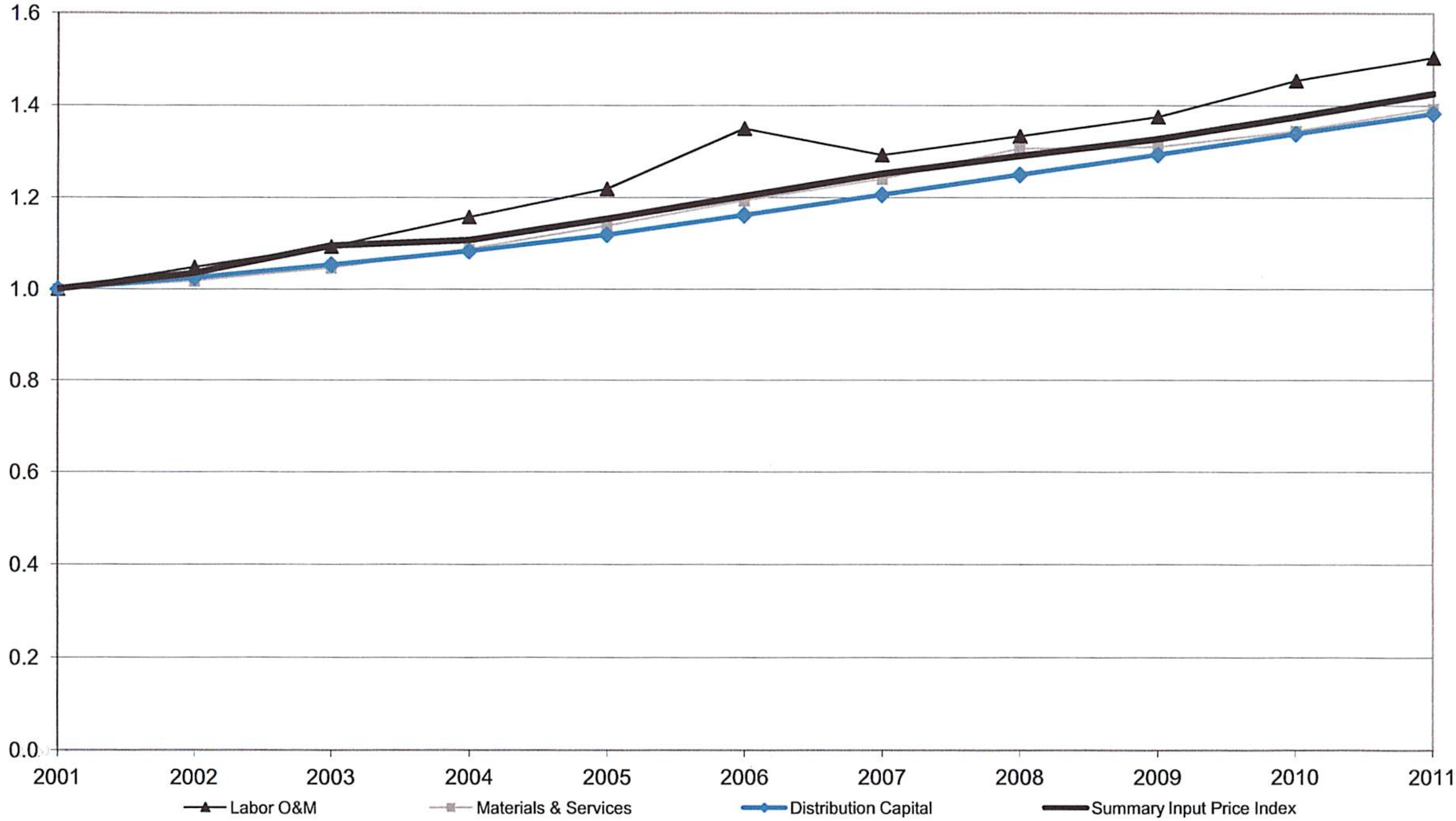
	Input Price Growth Rates				Summary Input Price Trend
	Distribution Capital	General Capital	Labor O&M[1]	Materials & Services[2]	
2002	2.4%	3.7%	4.7%	1.8%	3.17%
2003	2.6%	4.0%	4.1%	2.8%	4.19%
2004	2.6%	3.7%	5.7%	3.9%	1.61%
2005	3.4%	3.7%	5.1%	4.6%	3.98%
2006	3.7%	2.8%	10.1%	4.7%	3.93%
2007	3.6%	2.5%	-4.3%	3.9%	3.18%
2008	3.6%	3.5%	3.1%	5.2%	3.19%
2009	3.4%	2.3%	3.1%	0.2%	3.94%
2010	3.6%	1.2%	5.5%	2.7%	3.16%
2011	3.1%	2.9%	3.4%	3.6%	4.06%
Average Annual Growth Rate 2002-2011	**3.21%**	**3.02%**	**4.05%**	**3.32%**	**3.44%**

[1] Labor trend index is calculated residually for each company as the ratio of labor O&M expenses to the O&M labor quantity index.

[2] M&S price index constructed from detailed price indexes for power distribution utility materials and services prepared by Global Insight for its Power Planner information service.

Figure MNL-3

INPUT PRICE TRENDS OF SAMPLED UPPER NORTHEAST POWER DISTRIBUTORS



was calculated for most years as the growth rate of the national employment cost index ("ECI") for the salaries and wages of the utility sector of the U.S. economy plus the difference between the growth rates of multi-sector ECIs for workers in the Northeast and in the nation as a whole.

The quantity subindex for other O&M inputs was the ratio of the expenses for these inputs to the material and services price index. The trend in the subindex is then the difference between the trends in the expenses and the M&S price index.

A.4 Econometric Capital Cost Model

In the econometric capital cost models the dependent variable is capital cost divided by the capital price index. The COS method was used to compute the numerator and denominator of this ratio. The model thus effectively explains the capital quantity of each utility and is useful for identifying utilities with capital stocks that are small given their operating scale and other external business conditions.

Substantive variables in the model were logged prior to estimation. The parameter estimates are thus also estimates of the corresponding cost elasticities. A feasible GLS procedure was used in parameter estimation which corrects for autocorrelation and heteroskedasticity.

The capital cost model was estimated using data from a sample that includes utilities outside the Northeast. A large sample improves the precision of econometric parameter estimates. The utilities included in the sample for econometric research are listed in Table MNL-6.

Table MNL-7 provides details of the econometric capital cost model that was used to calculate the K factor. Inspecting the results, it can be seen that the parameter estimates for the explanatory variables of the model are generally sensible and all are statistically significant at a high confidence level. Real capital cost increased with the delivery volume and the number of customers served. Capital cost was lower the greater was the percentage of system assets overhead, cooling degree days, heating degree days, and the number of gas customers served. The trend variable's parameter estimate suggests that capital cost declines by 0.47% per year for other reasons not specified in the

Table MNL-6

Companies in the Econometric Cost Model Sample

Alabama Power
Appalachian Power
Arizona Public Service
Atlantic City Electric
Avista
Baltimore Gas & Electric
Bangor Hydro-Electric
Carolina Power & Light
Central Hudson Gas & Electric
Central Maine Power
Central Vermont Public Service
Cleveland Electric Illuminating
Connecticut Light & Power
Dayton Power & Light
Duke Energy Carolinas
Duke Energy Indiana
Duke Energy Ohio
Duquesne Light
El Paso Electric
Empire District Electric
Entergy Arkansas
Florida Power & Light
Florida Power
Georgia Power
Green Mountain Power
Gulf Power
Idaho Power
Indiana-Michigan Power
Indianapolis Power & Light
Jersey Central Power & Light
Kansas City Power & Light
Kansas Gas and Electric
Kentucky Power
Kentucky Utilities
Louisville Gas and Electric
Maine Public Service
Massachusetts Electric
Metropolitan Edison
Minnesota Power
Mississippi Power
Montana-Dakota Utilities
Narragansett Electric
Nevada Power
New York State Electric & Gas
Northern States Power
Nstar Electric
Ohio Edison
Oklahoma Gas and Electric
Orange and Rockland Utilities
Pacific Gas and Electric
PacifiCorp
Pennsylvania Electric
Pennsylvania Power
Potomac Electric Power
Public Service of Colorado
Public Service of Oklahoma
Public Service Electric and Gas
Puget Sound Energy
San Diego Gas & Electric
South Carolina Electric & Gas
Southern California Edison
Southern Indiana Gas and Electric
Southwestern Public Service
Tampa Electric
Toledo Edison
Tucson Electric Power
United Illuminating
Virginia Electric and Power
West Penn Power
Western Massachusetts Electric
Western Resources
Wisconsin Electric Power
Wisconsin Power and Light
Wisconsin Public Service

Table MNL-7

Econometric Capital Cost Benchmarking Model

VARIABLE KEY

N = Number of Electric Customers
V = Retail Delivery Volume
OH = % of Distribution Plant Overhead
NG = Number of Gas Customers
CDD = Cooling Degree Days
HDD = Heating Degree Days
Trend = Time Trend

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T-STATISTIC	P-VALUE
N	0.652	46.282	0.000
V	0.357	26.860	0.000
OH	-0.031	-2.289	0.022
NG	-0.008	-9.621	0.000
CDD	-0.022	-5.753	0.000
HDD	-0.026	-4.000	0.000
Trend	-0.005	-7.490	0.000
Constant	10.450	902.135	0.000
System Rbar-Squared	0.956		
Sample Period	2001-2011		
Number of Observations	814		

model. A 0.956 adjusted R^2 statistic suggests that the explanatory power of the model was high.

EXHIBIT MNL-2

REFERENCES

Denny, Michael, Melvyn A. Fuss and Leonard Waverman (1981), "The Measurement and Interpretation of Total Factor Productivity in Regulated Industries, with an Application to Canadian Telecommunications," in Thomas Cowing and Rodney Stevenson, eds., *Productivity Measurement in Regulated Industries*, (Academic Press, New York) pages 172-218.

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Tornqvist, L. (1936), "The Bank of Finland's Consumption Price Index", *Bank of Finland Monthly Bulletin*, 10, pages 1-8.

U.S. Department of Energy, *Financial Statistics of Major U.S. Investor-Owned Electric Utilities*, various issues.

BOARD STAFF RESPONSE TO UNDERTAKING OF EGDI

UNDERTAKING TCU1.2

REF: Tr.1 p17

DR. KAUFMANN TO PROVIDE A RESPONSE TO EGDI TCQ 2

RESPONSE

a) In preparing its April 2012 report, PEG did not amend the workpapers it developed for its December 2011 report in Alberta and which were provided in response to I.A1.Staff.EGD.12.

   However, during the Alberta proceeding, PEG did correspond with another consultant who wished to replicate PEG's April 2012 results. PEG sent this consultant a message which outlined the changes in the computer code necessary to update the capital "benchmark" year and reproduce PEG's April 2012 results by re-running the program. This message is replicated below:

   In order to move the benchmark year forward to 1994, we made the following changes to the code:

```
range

range if[year<=1994&year>=1950]

set wkai = wka*(45-(1994-year))/45

aggregate var[wkai] to[denom] by[pegid] sum

range

range if[year==1994]

set xka = (plngasgr-depgas)/denom

range

range if[year<=1994&year>=1950]
```

Witness: Dr. Lawrence Kaufmann, PEG

```
array years1 = (  1993 1992 1991 1990 1989 1988 1987 1986  1985 1984 1983 \
                  1982 1981 1980 \
                  1979 1978 1977 1976 1975 1974 1973 1972 1971 1970 \
                  1969 1968 1967 1966 1965 1964 1963 1962 1961 1960 \
                  1959 1958 1957 1956 1955 1954 1953 1952 1951 1950  )
```

Effectively, this ignores all the pre-1994 data and re-establishes the benchmark year at 1994. The first section of code creates a Triangularized weighted average for 1994 instead of 1983. The second part creates the benchmark year quantity of capital based on 1994 net plant (instead of 1983) and the triangularized weighted average. The third part backs out the pre-benchmark year quantities based on a 1994 benchmark instead of a 1983 benchmark.

The only new data not previously used are the 1994 values for gross plant and accumulated depreciation which are available in the kdata.xls file provided as part of the original working papers. I do not recall making any corrections or imputations to these data.

b) Each of the referenced files is an intermediate file generated by the computer code provided in I.A1.Staff.EGD.12 and then used again within the same code. The software used to write this code is SST. If a stakeholder owns the SST software, the referenced files can and will be generated by running the computer code on the dataset provided in I.A1.Staff.EGD.12.

   PEG could generate the referenced files by running the code ourselves and saving the intermediate files as program output. However, stakeholders would not be able to open those saved files unless they own a copy of SST. Stakeholders who do not own the SST software could generate the referenced files by re-coding the program into the language of a software program they own and are familiar with and then proceed to run the program.

BOARD STAFF RESPONSE TO UNDERTAKING OF EGDI

UNDERTAKING TCU1.3

REF: Tr.1 p20

DR. KAUFMANN TO PROVIDE THE ANSWERS TO EGDI TCQS 3A AND 3B AND TO PROVIDE THE PUBLICLY AVAILABLE B.C. STUDY

RESPONSE

Response to EGDI TCQ 3a:

I can confirm that PEG's TFP estimate for the US gas distribution industry, presented on behalf of the Consumer Coalition of Alberta (CCA) in December 2011, would have declined if the analysis period started in 2000 instead of 1996.

Response to EGDI TCQ 3b:

For the 2000-2009 sample period, PEG's estimated TFP trend for the US gas distribution industry in our December 2011 report for CCA was 1.0% per annum. Because PEG estimates TFP growth as the logarithmic growth rate in a TFP index, the TFP trend for the 2000-2009 can be computed simply by eliminating the average growth rates for the 1996-1999 years from the 1996-2009 "Productivity Index Results" presented in Table 2 of our report for CCA. The "Tables TCU1.3.xlxs" file shows these results on the amended Table 2; no other data or table needs to be amended, nor were any other data or tables amended, to produce this estimate of the industry's TFP trend for the requested, truncated sample period.

PEG's requested TFP study in British Columbia is attached. Chapter 3 presents PEG's TFP results for the US gas distribution industry.

Witness: Dr. Lawrence Kaufmann, PEG

Table 2

Productivity Index Results

	Output Quantity		Input Quantity		TFP	
	Sample	Western	Sample	Western	Sample	Western
2000	1.94%	2.78%	1.88%	-0.37%	0.06%	3.16%
2001	1.70%	2.74%	-1.69%	1.36%	3.39%	1.38%
2002	1.38%	1.88%	0.26%	0.29%	1.12%	1.59%
2003	1.10%	2.29%	0.89%	3.14%	0.21%	-0.85%
2004	1.33%	2.41%	1.15%	0.27%	0.18%	2.14%
2005	1.65%	3.48%	0.76%	1.38%	0.89%	2.11%
2006	1.23%	2.42%	-1.93%	-0.04%	3.16%	2.45%
2007	1.07%	2.20%	0.78%	0.72%	0.29%	1.48%
2008	0.77%	1.35%	-0.68%	-3.06%	1.45%	4.41%
2009	0.38%	0.46%	1.13%	3.39%	-0.75%	-2.93%
2000-2009	**1.25%**	**2.20%**	**0.25%**	**0.71%**	**1.00%**	**1.49%**

X Factor Research for Fortis PBR Plans

Mark Newton Lowry, President

David Alan Hovde, Vice President

Kaja Rebane, Economist

PEG Research LLC

Submitted On Behalf of

Commercial Energy Consumers Association of British Columbia

Errata Draft

7 January 2014

Pacific Economics Group Research, LLC

TABLE OF CONTENTS

1. Introduction

Fortis BC Energy ("FEI"), a gas utility, and Fortis BC ("FBC"), an electricity utility, have recently filed proposals for multiyear performance-based ratemaking ("PBR") plans with the British Columbia Utilities Commission ("BCUC" or "the Commission"). In each proposed plan, budgets for O&M expenses and capital expenditures ("capex") are escalated by formulas featuring an inflation measure, an X factor, and a scale escalator. Both companies have proposed an X factor of 0.50% for these indexes.

Black and Veatch ("B&V" or "the authors") were retained by Fortis to provide statistical research that could be used to design the X factors. In separate reports entered in the application of each company, B&V discuss the results of statistical research using data from the US gas and electric utility industries. Each study is purported to have used the "Kahn method" in the preparation of results. The B&V estimates of industry MFP trends are negative and far below the X factor proposed by Fortis.

Pacific Economics Group ("PEG") Research LLC is an economic consulting firm that is prominent in the field of PBR plan design. Research on energy utility input price and productivity trends is a company specialty. The PEG team has over 60 man-years of experience in the field. The practice is intercontinental in scope and has included projects in Australia, Britain, Europe, Japan, and Latin America. Work for diverse clients has given the company a reputation for objectivity and dedication to regulatory science.

The Commercial Energy Consumers Association of BC ("CEC") has retained PEG Research to prepare independent studies of rate escalation formulas for the two Fortis companies. This is the report on our research. Section 2 provides an introduction to price and productivity indexes and explains how they can be used to design such formulas. In Section 3 we report results of our research for the CEC on the price and productivity trends of US gas distributors using our preferred indexing methods. In Section 4 we report results of our research on the price and productivity trends of US power distributors. Section 5 discusses the choice of inflation measures. Section 6 provides an appraisal of the B&V research. Stretch factor recommendations are made in

Section 7. X factor recommendations are found in Section 8. Additional and more technical details of the research are found in the Appendix.

Dr. Lowry, senior author of this paper and principal investigator for the project, is the President of PEG Research. In that capacity, he has for many years supervised statistical research on the input price and productivity trends of gas and electric utilities. He has testified on indexing research and other PBR plan design issues on more than thirty occasions. He provided productivity research and testimony for BC Gas in its 1997 PBR application. Other venues for his testimony have included Alberta, California, Colorado, the District of Columbia, Hawaii, Illinois, Kentucky, Georgia, Maryland, Massachusetts, New Jersey, Oklahoma, Ontario, Oregon, New York, Quebec, Vermont, and Washington.

Before joining PEG, Dr. Lowry worked for many years at Christensen Associates, first as a senior economist and later as a Vice President and director of Regulatory Strategy. The key members of his group have joined him at PEG. Dr. Lowry's career has also included work as an academic economist. He has served as an Assistant Professor of Mineral Economics at the Pennsylvania State University and as a visiting professor at the Ecole des Hautes Etudes Commerciales in Montreal. His academic research and teaching stressed the use of mathematical theory and statistical methods in industry analysis. He has been a referee for several scholarly journals and has an extensive record of professional publications and public appearances. He holds a PhD in applied economics from the University of Wisconsin-Madison.

2. ARM DESIGN

Multiyear rate plans ("MRPs") are the most common approach to utility regulation around the world today. In such plans, a moratorium is placed on general rate cases for several years. An attrition relief mechanism ("ARM") often adjusts allowed rates or revenues automatically for changing business conditions between rate cases.[1] These mechanisms are designed before the start of the plan, and are external in the sense that they are insensitive to the costs of the utility during the plan period.

The ARM is one of the most important components of an MRP. Such mechanisms substitute for rate cases as a means to adjust utility rates for trends in input prices, operating scale, and other external business conditions that affect utility earnings. As such, they make it possible to extend the period between rate cases and strengthen utility performance incentives. The mechanism can be designed so that the expected benefits of improved performance are shared equitably between utilities and their customers.

ARMs can escalate rates, allowed revenue, or itemized cost budgets. Price caps have been widely used to regulate industries, such as telecommunications, where it is important to promote marketing flexibility while protecting core customers from cross-subsidization. Under revenue caps, the focus of escalator design is the growth in the allowed revenue needed to afford compensation for growing cost. Allowed revenue is sometimes called the target revenue, the revenue requirement, or "budget."

Revenue caps are often paired with a revenue decoupling mechanism that removes disincentives to promote efficient energy use. However, revenue caps have intuitive appeal with or without decoupling since revenue cap escalators provide compensation for *cost* growth whereas price cap escalators have the more complicated task of providing compensation for the *difference* between cost and billing determinant growth. As a consequence, revenue caps are sometimes used even in the absence of decoupling. Current examples of companies that operate under revenue caps without decoupling include two gas utilities in Alberta.

[1]The concept of an ARM is useful in discussions of PBR plans because escalators can apply to rates, allowed revenue, or detailed cost budgets.

2.1 Basic Indexing Concepts

The logic of economic indexes provides the rationale for using price and productivity research to design ARMs for revenue decoupling plans. To understand the logic it is helpful to first have a high-level understanding of input price and productivity indexes.

2.1.1 Input Price and Quantity Indexes

The growth trend in a company's cost can be shown using calculus to be the sum of the growth in an appropriately designed input price index ("*Input Prices*") and input quantity index ("*Inputs*").

trend Cost = trend Input Prices + trend Inputs. [1]

These indexes summarize trends in the input prices and quantities that make up the cost. The growth in each kind of index is a weighted average of the growth of the constituent subindexes. Both indexes use the cost share of each input group that is itemized in index design as weights. A cost-weighted input price index measures the impact of input price inflation on the cost of a bundle of inputs. A cost-weighted input quantity index measures the impact of input quantity growth on cost. Capital, labor, and miscellaneous materials and services are the major classes of base rate inputs used by energy distributors such as Fortis.

The calculation of input quantity indexes is complicated by the fact that firms typically use numerous inputs in service provision. This complication can be contained when credible summary input price indexes are readily available for a group of inputs such as labor. Rearranging the terms of [1] we obtain

trend Inputs = trend Cost - trend Input Prices. [2]

Input quantity growth is calculated as the growth in inflation-adjusted (a/k/a "real") cost. This is the approach to input quantity trend calculation that is most widely used in utility productivity research. We can, for example, calculate the growth in the quantity of labor by taking the difference between salary and wage expenses and a salary and wage price index.

2.1.2 Productivity Indexes

Basic Idea

A productivity index is the ratio of an output quantity index ("*Outputs*") to an input quantity index.

$$Productivity = \frac{Outputs}{Inputs}. \qquad [3]$$

It is used to measure the efficiency with which firms convert production inputs into the goods and services that they offer. Some productivity indexes are designed to measure productivity *trends*. The growth trend of such a productivity index is the *difference* between the trends in the output and input quantity indexes.

$$trend\ Productivity = trend\ Outputs - trend\ Inputs.^{2} \qquad [4]$$

Productivity grows when the output index rises more rapidly (or falls less rapidly) than the input index. Productivity can be volatile but tends to grow over time. The volatility is due to fluctuations in output and the uneven timing of certain expenditures. The productivity of O&M inputs tends to be much more volatile than the productivity of capital. Volatility tends to be greater for individual companies than for an aggregation of companies such as a regional industry.

The scope of a productivity index depends on the array of inputs that are considered in the input quantity index. Some indexes measure productivity in the use of a single input class such as labor. A *multifactor* productivity ("MFP") index measures productivity in the use of multiple inputs. A *total factor* productivity ("TFP") index measures productivity in the use of *all* inputs. Indexes used in ARM design are sometimes called TFP indexes but are better described as MFP indexes since multiple input categories are considered but some inputs (*e.g.* purchased power) are usually excluded.

Output Indexes

The output (quantity) index of a firm or industry summarizes trends in the amounts of goods and services produced. Growth in each output dimension that is

[2] For any ratio Y/X, $\ln[(Y_t/X_t)/(Y_{t-1}/X_{t-1})] = \ln[(Y_t/Y_{t-1})/(X_t/X_{t-1})] = \ln(Y_t/Y_{t-1}) - \ln(X_t/X_{t-1})$

itemized is measured by a subindex. The growth in the summary output index is a weighted average of the growth in the subindexes.

In designing an output index, choices concerning subindexes and weights should depend on the manner in which the index is to be used. One possible objective is to measure the impact of output growth on *revenue*. In that event the subindexes should measure trends in *billing determinants* and the weight for each itemized determinant should be its share of revenue.[3] In this report we denote a revenue-weighted output index by $Outputs^R$. A productivity index calculated using $Outputs^R$ will be labeled $Productivity^R$.

$$trend\ Productivity^R = trend\ Outputs^R - trend\ Inputs. \qquad [5a]$$

Another possible objective of output research is to measure the impact of output growth on *cost*. In that event it can be shown that the subindexes should measure the dimensions of operating scale (a/k/a "workload") that drive cost. If there is more than one pertinent scale variable, the weights for each variable should reflect the relative cost impacts of these drivers.

The sensitivity of cost to a small change in the value of a business condition variable is commonly measured by its cost "elasticity." Elasticities can be estimated econometrically using historical data on the operations of a group of utilities. The weight for each output variable can then be assigned its share in the sum of the estimated scale-related cost elasticities. Extensive econometric research has been undertaken on the drivers of total gas and electric power distribution cost. Much less is known about the drivers of capex or power transmission total cost.

A multicategory output index with elasticity weights is unnecessary if econometric research reveals that there is one dominant cost driver, or that the trend in a single output variable is highly correlated with the trend in a more sophisticated output index. A productivity index calculated using a cost-based output index will be labeled $Productivity^C$.

$$trend\ Productivity^C = trend\ Outputs^C - trend\ Inputs. \qquad [5b]$$

This may fairly be described as a "cost efficiency index."

[3] This approach to output quantity indexation is due to the French economist Francois Divisia.

Sources of Productivity Growth

Research by economists has found the sources of productivity growth to be diverse. One important source is technological change. New technologies permit an industry to produce given output quantities with fewer inputs.

Economies of scale are another important source of productivity growth. These economies are available in the longer run if cost has a tendency to grow less rapidly than operating scale. A company's potential to achieve incremental scale economies depends on the pace of its workload growth. Incremental scale economies (and thus productivity growth) will typically be lower the slower is output growth.

A third important source of productivity growth is change in X inefficiency. X inefficiency is the degree to which a company fails to operate at the maximum efficiency that technology and other external business conditions allow. Productivity growth will increase (decrease) to the extent that X inefficiency diminishes (increases). The potential of a company for productivity growth from this source is greater the lower is its current efficiency level.

Another driver of productivity growth is changes in the miscellaneous business conditions, other than input price inflation and workload growth, which affect cost. A good example for an electric power distributor is the share of distribution lines that are undergrounded. Because underground lines are more costly, an increase in the percentage of lines that are undergrounded will tend to slow MFP growth.

2.2 Use of Index Research in ARM Design

Research on the input price and productivity trends of utilities has been used for more than twenty years to design ARMs. This approach produces automatic adjustments for changing inflation conditions without weakening utility performance incentives. The indexing approach also has the benefit of exposing the utility to an external productivity growth standard. For this reason, MRPs that feature index-based ARMs are sometimes called PBR plans.

This approach to ARM design originated in the United States where detailed, standardized data on the operations of a large number of utilities have been available for many years from state and federal agencies. First applied in the railroad industry, PBR has subsequently been used to regulate telecom, gas, electric, and oil pipeline utilities. The methodology is now used in several additional countries. ARMs based on indexing research are today used more widely to regulate utilities in Canada than in the United States. For example, some seventy power distributors in Ontario currently operate under PBR, as do all large gas and electricity distributors in Alberta.

2.2.1 Price Cap Indexes

Early work to use indexing in ARM design focused chiefly on *price* cap indexes ("PCIs"). We begin our explanation of the logic for such research (a/k/a "index logic") by considering the growth in the prices charged by an industry that earns, in the long run, a competitive rate of return.[4] In such an industry, the long-run trend in revenue equals the long-run trend in cost.

$$trend\ Revenue = trend\ Cost. \qquad [6]$$

The trend in the revenue of any firm or industry can be shown using calculus to be the sum of the trends in revenue-weighted indexes of its output prices ("*Output Prices*") and billing determinants.

$$trend\ Revenue\ =\ trend\ Outputs^R + trend\ Output\ Prices. \qquad [7]$$

Recollecting relation [1], it follows that the trend in output prices that permits revenue to track cost is the difference between the trends in an input price index and a multifactor productivity index of MFP^R form.

$$\begin{aligned} trend\ Output\ Prices\ &= trend\ Input\ Prices - (trend\ Outputs^R - trend\ Inputs) \\ &= trend\ Input\ Prices - trend\ MFP^R. \qquad [8] \end{aligned}$$

The result in [8] provides a conceptual framework for the design of PCIs of general form

$$trend\ Rates = trend\ Inflation - X\ . \qquad [9a]$$

where

$$\mathrm{X} = \overline{MFP^R} + Stretch \qquad [9b]$$

Here X, the "X factor." is calibrated to reflect a base MFP^R growth target ("$\overline{MFP^R}$"). A "stretch factor," established in advance of plan operation, is sometimes added to the

[4] The assumption of a competitive rate of return applies to unregulated, competitively structured markets. It is also applicable to utility industries and even to individual utilities.

formula which slows PCI growth in a manner that shares with customers the financial benefits of performance improvements that are expected during the MRP. Since the X factor often includes a stretch factor, it is sometimes said that index research has the goal of "calibrating" X.

2.2.2 Revenue Cap Indexes

Index research can also be used to design revenue cap escalators. Several approaches to revenue cap index ("RCI") design are consistent with index logic. One approach is grounded in the following basic result of cost theory:

$$\textit{growth Cost} = \textit{growth Input Prices} - \textit{growth Productivity}^{C} + \textit{growth Outputs}^{C}. \qquad [10a]$$

Cost growth is the difference between input price and cost efficiency growth plus the growth in operating scale, where growth in scale is measured by a cost-based output index. This result provides the basis for an RCI of general form

$$\textit{growth Revenue} = \textit{growth Input Prices} - X + \textit{growth Outputs}^{C} \qquad [10b]$$

where

$$X = \overline{MFP^{C}} + Stretch. \qquad [10c]$$

In gas and electric power distribution, the number of customers served is an especially important output variable driving cost in the short and medium term. To the extent that this is true, $Outputs^{C}$ can be reasonably approximated by growth in the number of customers served and there is no need for the complication of a multidimensional output index. Relation [10a] can be restated as

$$\begin{aligned}\textit{growth Cost} &\\ &= \textit{growth Input Prices} - (\textit{growth Customers} - \textit{growth Inputs}) + \textit{growth Customers}\\ &= \textit{growth Input Prices} - \textit{growth } MFP^{N} + \textit{growth Customers} \qquad [11a]\end{aligned}$$

where MFP^{N} is an MFP index that uses the number of customers to measure output.

Rearranging the terms of [11a] we obtain

$$\begin{aligned}\textit{growth Cost} - \textit{growth Customers}&\\ &= \textit{growth } (\textit{Cost/Customer}) = \textit{growth Input Prices} - \textit{growth } MFP^{N}. \qquad [11b]\end{aligned}$$

This provides the basis for the following "revenue per customer" ("RPC") index formula.

$$\textit{growth Revenue/Customer} = \textit{growth Input Prices} - X \qquad [11c]$$

where

$$X = \overline{MFP^{N}} + Stretch \ . \qquad [11d]$$

This general formula for the design of a revenue cap escalator is currently used in the PBR plans for Gazifere, ATCO Gas, and AltaGas in Canada. The Regie de l'Energie in Quebec recently directed Gaz Metro to develop an MRP featuring RPC indexes. RPC indexes have previously been used by Southern California Gas and Enbridge Gas Distribution ("EGD"), the largest gas distributors in the US and Canada, respectively.

2.2.3 Index-Based Cost Targets

Formula [10a] can also be used to calculate revenue requirements for individual cost categories. For example, a formula for non-fuel O&M expenses is

$$\begin{aligned} &\textit{growth Cost}_{O\&M} \\ &= \textit{growth Input Prices}_{O\&M} - (\textit{growth Outputs}^{C}_{O\&M} - \textit{growth Inputs}_{O\&M}) \\ &\qquad + \textit{growth Outputs}^{C}_{O\&M} \\ &= \textit{growth Input Prices}_{O\&M} - \textit{growth Productivity}^{C}_{O\&M} + \textit{growth Outputs}^{C}_{O\&M} \qquad [12] \end{aligned}$$

where

$\textit{Input Prices}_{O\&M}$ = Price index for O&M inputs

$\textit{Outputs}^{C}_{O\&M}$ = Cost-based output index applicable to O&M

$\textit{Productivity}^{C}_{O\&M}$ = Productivity index for O&M calculated using $\textit{Outputs}^{C}$.

Where a multidimensional output index is warranted these may use cost elasticity weights. Formulas with elasticity-weighted output measures have been used by the Essential Services Commission ("ESC") in the populous state of Victoria, Australia to establish multiyear O&M budgets for gas and electric distributors.[5] In the energy distribution business, however, we have noted that the number of customers served is the dominant output variable driving cost in the short and medium term. $\textit{Outputs}^{C}$ can then be reasonably approximated sometimes by growth in the number of customers served and there is no need to have a multidimensional output index with elasticity weights. Relation [12] can then be restated as

$$\begin{aligned} &\textit{growth Cost}_{O\&M} \\ &= \textit{growth Input Prices}_{O\&M} - \textit{growth Productivity}^{N}_{O\&M} + \textit{growth Customers} \qquad [13a] \end{aligned}$$

[5]The ESC uses a more British style of incentive regulation which involves multiyear cost forecasts.

where the productivity index uses the number of customers to measure output. This general formula was used in now expired O&M budget caps for EGD and Gazifere.

Rearranging the terms of the formula we obtain

$$\begin{aligned}&\textit{growth Cost}_{O\&M} - \textit{growth Customers}\\ &\quad = \textit{growth}\ (\textit{Cost}_{O\&M}/\textit{Customer})\\ &\quad = \textit{growth Input Prices} - \textit{growth Productivity}^{C}.\end{aligned}$$

This provides the basis for the cost target formula

$$\textit{Growth Cost}_{O\&M}/\textit{Customer} = \textit{growth Inflation} - X. \qquad [13b]$$

Cost per customer formulas have been used to escalate *O&M* budgets in IR plans of FortisBC, Terasen Gas, and Vermont Gas Systems.

2.2.4 Choosing a Productivity Peer Group

Research on the productivity of other utilities can be used in several ways to calculate base productivity growth targets. One option is to use the productivity trend of the entire industry to calibrate X. This approach is sometimes described as simulating the outcome of competitive markets. A competitive market paradigm has broad appeal.

On the other hand, individual firms in competitive markets routinely experience windfall gains and losses. Our discussion in Section 2.1.2 of the sources of productivity growth implies that differences in the external business conditions that drive productivity growth can cause utilities to have different productivity trends. For example, power distributors that are experiencing brisk growth in the number of electric customers served are more likely to realize economies of scale than distributors experiencing slow growth. Similarity in input prices is also important in reducing expected windfalls. There is thus considerable interest in methods for customizing X factors to reflect local business conditions.

The most common approach to customization has been to calibrate X using the input price and productivity trends of similarly situated (a/k/a “peer”) utilities. The utilities are usually but not always chosen from the surrounding region. The following principles are useful in choosing a peer group. First, the average productivity trend of the group should be insensitive to the productivity trend of individual utilities that would be subject to the PBR plan. This may be called the externality criterion. It is desirable, secondly, for the region to be broad enough that the productivity trend is not dominated by the actions of any handful of utilities. This may be called the size criterion. A third criterion is that the region should be one in which external business conditions that influence input price and productivity growth are similar to those of utilities that may be subject to the indexing plan. This may be called the "no windfalls" criterion. The relevant business conditions for a power distributor, for example, include the pace of customer growth and changes in the extent of system undergrounding.

2.2.5 Inflation Measure Issues

Index logic suggests that the inflation measure of an ARM should in some fashion track utility input price inflation. For incentive reasons, it is preferable that the inflation measure track the input price inflation of utilities *generally* rather than the prices actually paid by the subject utility.

Several issues in the choice of an inflation treatment must still be addressed. One is whether the inflation measure should be *expressly* designed to track utility industry input price inflation. There are several precedents for the use of utility-specific inflation measures in MRP rate escalation mechanisms. Such a measure was used in one of the world's first large scale MRPs, which applied to U.S. railroads. Such measures have also been used in MRPs for Canadian railroads and for energy utilities in Alberta, California, and Ontario. The development of industry-specific inflation measures for energy utilities is facilitated by the availability of indexes for certain utility inputs from private vendors and government agencies.

Notwithstanding such precedents, the majority of PBR plans approved worldwide do not feature industry-specific input price indexes. They instead feature measures of economy-wide (a/k/a "macroeconomic") price inflation. Gross domestic product price indexes ("GDPPIs") and consumer price indexes ("CPIs") are both widely used for this purpose. In the US and Canada alike, GDPPIs are a featured government measure of inflation in prices of the economy's final goods and services. Final goods and services consist chiefly of consumer products. However, GDPPIs track inflation in a broader range of products that includes government services and capital equipment.

Macroeconomic inflation measures have some advantages over industry-specific measures in ARM design. One is that they are available, at little or no cost, from government agencies. There is then no need to go through the chore of annually recalculating complex indexes or purchasing costly utility inflation data from private vendors. Customers are more familiar with macroeconomic price indexes (especially CPIs). The task of choosing an industry-specific price index during the proceeding that establishes a PBR Plan is also sidestepped. The design of a capital price for such an index can be especially controversial.

When a macroeconomic inflation measure is used, the ARM must be calibrated in a special way if it is to reflect industry cost trends. Suppose, for example, that the inflation measure is the comprehensive GDPPI. In that event we can restate the revenue per customer index in [11c], for example, as

$$\textit{growth Revenue/Customer} = \textit{growth GDPPI} - \left[\textit{trend MFP} + (\textit{trend GDPPI} - \textit{trend Input Prices}_{Industry}) + \textit{Stretch Factor}\right] \qquad [14]$$

It follows that an ARM with the GDPPI as the inflation measure can still conform to index logic provided that the X factor effectively corrects for any tendency of GDPPI growth to differ from industry input price growth. The term in parentheses is sometimes called the "inflation differential."

Consider now that the GDPPI is a measure of *output* price inflation. Due to the broadly competitive structure of the US and Canadian economies, we can utilize relation [8] to predict that the long-run trend in the GDPPI is the difference between the trends in input price and MFP indexes for the economy.

$$\textit{trend GDPPI} = \textit{trend Input Prices}^{Economy} - \textit{trend MFP}^{Economy}. \qquad [15]$$

Relations [14] and [15] can be combined to produce the following formula for a revenue per customer escalator.

$$\textit{growth Revenue/Customer} = \textit{growth GDPPI} - \begin{bmatrix} \left(\textit{trend MFP}^{Industry} - \textit{trend MFP}^{Economy}\right) \\ + \left(\textit{trend Input Prices}^{Economy} - \textit{trend Input Prices}^{Industry}\right) + \textit{Stretch} \end{bmatrix} \qquad [16]$$

This formula suggests that when the GDPPI is employed as the inflation measure, the revenue per customer index can be calibrated to track industry cost trends when the X factor has two calibration terms: a "productivity differential" and an "input price differential". The productivity differential is the difference between the MFP trends of the industry and the economy. X will be larger, slowing revenue growth, to the extent that the industry MFP trend exceeds the economy-wide MFP trend embodied in the GDPPI.

Provided that the input price trends of the industry and the economy are fairly similar, the growth trend of the GDPPI can thus be expected to be slower than that of the industry-specific input price index by the trend in the economy's MFP growth. In an economy with rapid MFP growth this difference can be substantial. X factor calibration is warranted only to the extent that the input price and productivity trends of the utility industry differ from those of the economy.

The MFP trend of the US economy is believed to be fairly brisk. In the last ten years, for example, the US federal government's MFP index for the private business sector has averaged 1.1% average growth. A sizable adjustment to the X factor is thus warranted in the US when the GDPPI is used as the inflation measure. In Canada, however, the analogous MFP index has declined by 0.45% annually on average over the last ten years.

The input price differential is the difference between the input price trends of the economy and the industry. X will be larger (smaller) to the extent that the input price trend of the economy is more (less) rapid than that of the industry. The input price trends of a utility industry and the economy can differ for several reasons. One possibility is that prices in the industry grow at different rates than prices for the same inputs in the economy as a whole. For example, labor prices may grow more rapidly to the extent that utility workers have health care benefits that are better than the norm. Another possibility is that the prices of certain inputs grow at a different rate in some regions than they do on average throughout the economy. It is also noteworthy that the energy distribution industry has a different and more capital-intensive mix of inputs than the economy.

Whether or not the X factor properly reflects *long*-term inflation trends, macroeconomic inflation measures vary in their ability to track input price inflation year to year. Some are more volatile than others, and volatility typically results from fluctuation in the prices of commodities, such as food and fuel, that have little relevance for utility cost. Inflation measures with irrelevant volatility increase utility operating risk.

2.2.6 Long Run Productivity Trends

An important issue in the design of a ARM is whether it should be designed to track short-run or long-run industry cost trends. An index designed to track short-run growth will also track the long run growth trend if it is used over many years. An alternative approach is to design the index to track *only* long-run trends. Different approaches can, in principle, be taken for the input price and productivity components of the ARM.

Different treatments of input price and productivity growth are in most cases warranted. The inflation measure should track *short-term* input price growth. Meanwhile, productivity research for X factor calibration commonly focuses on discerning the current *long-run* productivity trend. This is the trend in productivity that is unaffected by short-term fluctuations in outputs and/or inputs. The long run productivity trend is faster than the trend during a short-lived surge in input growth or lull in output growth but slower than the trend during a short-lived lull in input growth or surge in output growth.

This general approach to PCI design has important advantages. The inflation measure exploits the greater availability of inflation data. Making the PCI responsive to short term input price growth reduces utility operating risk without weakening performance incentives. Having X reflect the long run industry MFP trend, meanwhile, sidesteps the need for more timely cost data and avoids the chore of annual MFP calculations.

To calculate the long-run productivity trend using indexes it is common to use a lengthy sample period. However, a period of more than twenty years may be unreflective of the current state of technological change. Quality data are often unavailable for sample periods of even this length. The need for a long sample period is lessened to the extent that volatile costs are excluded from the study and the output index does not assign a heavy weight to the volatile output measures such as delivery volumes and system peak demand.

2.2.7 Dealing With Cost Exclusions

Many multiyear rate plans recover certain costs outside of the ARM. Costs targeted for exclusion are sometimes said to be "Y factored." The exclusions affect the research method that is appropriate for calibrating the X factor. Suppose, for example, that expenses for the procurement of energy are not addressed by the indexing mechanism of the PBR plan. These costs should then be excluded from the definition of cost used in the index research. Similarly, the exclusion of a sizable share of routine capex from the indexing mechanism may make it appropriate to exclude some plant additions from the MFP research.

2.3 Further Issues in Index Research

2.3.1 Capital Cost

Trends in the price and quantity of capital play a critical role in the measurement of trends in the multifactor productivity and prices of utility inputs. Summary input price and quantity indexes are, after all, cost-weighted, and capital typically accounts for half or more of total cost. A practical means must thus be found to calculate capital cost and to decompose it into consistent price and quantity indexes such that

$$growth\ Cost^{Capital} = growth\ Price^{Capital} + \text{growth}\ Quantity^{Capital}. \qquad [17]$$

Several formulas for capital price and quantity indexes are available.

The capital quantity index is, effectively, an index of the trend in the real (inflation-adjusted) cost of depreciated plant. Indexes of construction costs are commonly used to measure plant addition price trends in utility research. The rate base of an energy distributor tends to grow over time due to system expansion and construction cost inflation. However, capital quantity indexes of energy distributors sometimes display a negative trend.

The capital price index measures the trend in the cost of owning a unit of capital. It is sometimes called a "rental" or "service" price since, in a competitive rental market, the trend in prices would tend to reflect the trend in the unit cost of capital ownership. The monthly charge for an automobile lease, for instance, should reflect the monthly cost to the lessor of owning the automobile.

The components of capital cost include depreciation and the return on investment. Capital cost therefore depends on construction prices, depreciation rates, and the rate of return on capital. A capital service price index should reflect the trends in these conditions.

Utilities use several kinds of financing in their operations. Debt and equity are the principal categories. Change in the rates of return ("RORs") on different kinds of investments can differ considerably.

Utilities have diverse methods for calculating depreciation expenses. In calculating capital costs and quantities, it is therefore desirable in productivity research to rely chiefly on the companies for the value of plant *additions* and then use a standardized depreciation treatment to construct a capital quantity index. Since the quantity of capital on hand may involve plant added thirty to fifty years ago, it is desirable to have plant addition data for many years in the past. For some of the earliest years for which plant addition data are needed, the data are often unavailable and the capital quantity must be imputed using plant value data and construction price indexes.

Three practical methods are well-established for calculating capital costs that can be decomposed into input price and quantity indexes. All have been used over the years in utility productivity evidence. The choice of a capital costing method is an important issue in X factor calibration.

Geometric Decay

The critical assumptions of the geometric decay ("GD") approach are twofold.

- Utility plant is valued in *current* dollars so that plant value reflects the cost of asset replacement.
- Plant depreciates at a constant rate.

Both assumptions differ from those used to compute capital cost in North American utility regulation.

Current valuation of plant means that owners profit from capital gains. If the value of assets is rising, the *net* cost of plant ownership can be appreciably less than the *gross* due to capital gains. The capital service price should then reflect the expected *net* cost of owning a unit of plant.

While GD price and quantity formulas are mathematically elegant, they have serious practical implementation problems in an X factor calibration exercise. One is that there is no established method of modeling the expected growth of the real rate of return. Another is the unusual instability of capital cost and the capital price index. This stems from the fact that the rate of return does not always rise when asset price (or construction cost) inflation accelerates. The real rate of return is, in practice, considerably more volatile than the nominal rate of return.

The instability of the capital service price using this approach to capital costing means that it must be smoothed before its trend can be calculated. Different approaches to smoothing have materially different effects on input price trend calculations. The proper approach to smoothing can be a source of dispute, and smoothing does not always eliminate service price volatility.

The GD method has nonetheless been widely used in productivity research. Despite the controversy that can arise over input price differentials, it has been used many times in index research intended to calibrate X factors. An example is the X factor testimony of Dr. Lowry in his PBR evidence for BC Gas.

One Hoss Shay

The one hoss shay approach to capital costing assumes that plant does not depreciate gradually but, rather, all at once as the asset reaches the end of its service life. Plant is valued in current dollars, so that capital gains occur and capital cost and service price instability are once again issues. Although the assumptions underlying the one hoss shay method are very different from those used to compute capital cost in utility regulation, the method has been used occasionally in research intended to calibrate utility X factors. An example is the testimony of NERA in the recent Alberta PBR proceeding.

Cost of Service

The cost of service ("COS") approach to capital costing is more consistent with the way that capital cost is calculated in utility regulation. It is based on the assumption of straight line depreciation and the historic (a/k/a "book") valuation of plant. There are no capital gains from asset appreciation.

Because of historical valuation the capital price is a function not simply of the *current* construction price but, rather, of a *weighted average* of current and past values.

We are interested then in measuring the extent to which the cost of constructing plant that is, for example, two, four, and twenty years old is higher this year than it was last year. The weight for construction cost of a given vintage should be larger the larger is its representation in the value of the rate base. Weights tend to be larger for more recent years than for earlier years because construction costs were higher and there has been less cumulative depreciation.

Although the COS approach to capital costing has intuitive appeal, the formulas required to implement it are somewhat complicated and are more efficiently set forth in computer code rather than a spreadsheet. Computer code has, however, been used in most productivity studies presented in PBR proceedings. For example, code has been used routinely in the productivity research and testimony by PEG for the Ontario Energy Board.

The Kahn method for X factor calibration, which we discuss at length in Section 6 below, is implicitly based on COS capital cost measurement. Dr. Kahn's method has been employed by B&V in its work for Fortis. PEG has used a COS method in studies presented in testimony for Atlantic City Electric, Central Maine Power, Central Vermont Public Service, the Consumers' Coalition of Alberta, Delmarva Power, Fitchburg Gas & Electric, the Ontario Energy Board, Potomac Electric Power, Public Service of Colorado, Gaz Metro, and the Gaz Metro Task Force. The base productivity growth target in the current price cap plans of Ontario power distributors is based on productivity research that used COS capital costing. The methodology also informed the choice of an X factor for the revenue cap index of Central Vermont Public Service.

We have chosen the COS method for use in our work for the CEC. Its principal advantage is its greater relevance in a ratemaking application. The COS method is also more consistent with the capital cost methodology of B&V in this proceeding. This makes it more useful in an appraisal of the B&V method.

2.3.2 Data Quality

The quality of data used in index research has an important bearing on the relevance of results for ARM design. Generally speaking, it is desirable to have publicly available data drawn from a standardized collection form such as those managed by government agencies. The best quality data of this kind are often gathered by commercial venders that put in extra effort to ensure its quality and can spread the cost of their work amongst numerous subscribers. Data quality also has a temporal dimension. It is customary for statistical cost research used in the design of index-based ARMs to include the latest data available.

Data limitations discourage use of Canadian utility data in ARM design. Data collection is not standardized across Canada, and the data reported in BC and other individual provinces have changed over the years. Data for many years of plant additions, such as are needed to calculate accurate capital quantity trends, are generally unavailable. The best available data for calibrating the X factors of BC energy utilities are found in the United States. Data on U.S. productivity trends have been considered by Canadian regulators in designing ARMs for BC Gas, Gaz Metro, EGD, Union Gas, Alberta's energy distributors, and Ontario's power distributors.

3. Index Research: US Gas Distribution

3.1 Data

The chief source of our data on the costs incurred by US gas distributors is reports to state regulators. These reports are fairly standardized since they often use as templates the Form 2 that interstate gas pipeline companies file with the FERC. A Uniform System of Accounts is available for this form. The chief source for our data on gas utility operating scale is Form EIA 176. Gas utility operating data from both of these sources are compiled by respected commercial venders. We obtained most of the gas operating data used in this study from SNL Financial.[6]

Other data sources were also employed in our productivity research. These were used primarily to measure input price trends. The supplemental sources of price data were Whitman, Requardt & Associates, the Regulatory Research Associates unit of SNL Financial, the Bureau of Labor Statistics ("BLS") of the U.S. Department of Labor, and Global Insight (formerly DRI-McGraw Hill).

Our calculations of the productivity trends of US gas distributors are based on quality data for 64 utilities. The sample includes most of the larger distributors in the United States. Some of the sampled distributors also provide gas transmission and/or storage services but all were involved more extensively in gas distribution. The sampled distributors are listed in Table 1.

3.2 Index Details

3.2.1 Scope

We calculated indexes of trends in the O&M, capital, and multifactor productivity and input prices of each sampled utility in the provision of gas services. Itemized costs attributed to electric services provided by combined gas and electric utilities were excluded from the analysis. We also excluded certain costs that are itemized on U.S. data forms and are unlikely to be subject to indexing in the PBR plan of Fortis. The costs

[6] For a few of the sampled companies, the SNL data were deemed insufficient in some of the earliest years of the sample period. In such cases, we used data from sources we have used in the past such as the GasDat service of Platts.

Table 1

Companies in PEG's Gas Distribution Indexing Sample

Alabama Gas Corporation
Avista Corporation
Baltimore Gas and Electric Company
Berkshire Gas Company
Cascade Natural Gas Corporation
Central Hudson Gas & Electric Corp
Citizens Energy Group
Columbia Gas of Kentucky
Columbia Gas of Maryland
Columbia Gas of Massachusetts
Columbia Gas of Ohio, Incorporated
Columbia Gas of Pennsylvania, Inc.
Columbia Gas of Virginia
Connecticut Natural Gas Corporation
Consumers Energy Company
Corning Natural Gas Corporation
Duke Energy Ohio, Inc.
East Ohio Gas Company
Equitable Gas Company, LLC
Hope Gas, Inc.
Indiana Gas Company, Inc.
Intermountain Gas Company
Laclede Gas Company
Louisville Gas and Electric Company
Madison Gas and Electric Company
Michigan Consolidated Gas Company
Mountaineer Gas Company
National Fuel Gas Distribution
New Jersey Natural Gas Company
New York State Electric & Gas Corp
Niagara Mohawk Power Corporation
North Shore Gas Company
Northern Illinois Gas Company
Northern Indiana Public Service Co.
Northern States Power Company - WI
Northwest Natural Gas Company
NSTAR Gas Company
Ohio Gas Company
Ohio Valley Gas Corporation
Orange and Rockland Utilities, Inc.
Pacific Gas and Electric Company
PECO Energy Company
Peoples Gas System
Peoples Natural Gas Company
Pike Natural Gas Company
Public Service Company of Colorado
Public Service Electric and Gas Company
Puget Sound Energy, Inc.
Questar Gas Company
Rochester Gas and Electric Corp
San Diego Gas & Electric Co.
Sierra Pacific Power Company
South Carolina Electric & Gas Co.
South Jersey Gas Company
Southern California Gas Company
Southern Connecticut Gas Company
Southern Indiana Gas and Electric
St. Joe Natural Gas Co, Inc.
St. Lawrence Gas Company, Inc.
Vermont Gas Systems, Inc.
Virginia Natural Gas, Inc.
Washington Gas Light Company
Wisconsin Gas LLC
Yankee Gas Services Company

Sample comprises 64 utilities

excluded for this reason included expenses for gas supply, gas transmission by others, taxes, and pensions and other benefits. We excluded customer service and information expenses for two reasons. These costs grew briskly during the sample period for many utilities due to the growth in utility DSM programs. DSM programs are not covered by the indexing provisions of the proposed PBR plans. We also excluded the costs of uncollectible bill expenses as these costs grew rapidly in the later years of the sample period due to the recession.

The applicable total cost was calculated as the sum of applicable O&M expenses and the costs of gas plant ownership. The index calculations required the breakdown of cost into two input categories: capital and O&M inputs. O&M inputs comprise labor, materials, and services. Material and service (“M&S”) inputs is a residual input category that includes the O&M services of contractors, insurance, real estate rents, equipment leases, materials, and miscellaneous other goods and services. The cost shares for capital excluded taxes. The calculation of capital cost is discussed further in Appendix Section 4.

3.2.2 Output Measure

Our output specification is intended to measure the effect of output growth on cost. The trend in the workload was measured by the number of customers served. We show in Section 2.2.2 above that this is the output specification that is relevant to the design of a revenue per customer or cost per customer index.

3.2.3 Input Quantity Index

The growth rate in the input quantity index of each sampled distributor is a weighted average of quantity subindexes for capital and O&M inputs.

3.2.4 Input Price Index

The growth rate in the input price index of each sampled distributor was a weighted average of the growth rates in price subindexes for capital and O&M inputs. The weights were based on the shares of these input classes in each company’s applicable gas distributor cost.

3.2.5 Sample Period

In choosing a sample period for an indexing study used in X factor calibration, it is generally desirable that the period include the latest year for which all of the requisite data are available. In the present case this year is 2012, but some data became available only recently. It is also desirable for the sample period to reflect the long-run productivity trend. We generally desire a sample period of at least 10 years to fulfill this goal. A long sample period, however, may not be indicative of the latest technology trend. Moreover, the accuracy of the measured capital quantity trend is enhanced by having a start date for the indexing period that is several years after the first year that good capital cost data are available. It should also be noted that 2011 was a year of recovery in the United States from the severe recession of 2008-09. The sensitivity of our productivity results to this circumstance is lessened by a sample period of at least ten years and our choice of the number of customers as the output measure. We attempt to balance all of these considerations by presenting productivity results for the thirteen year 1999 to 2011 period.

3.3 INDEX RESULTS

Tables 2a and 2b and Figure 1 report annual growth rates in the gas distributor productivity and component output and input quantity indexes. Inspecting the results in Table 2a, it can be seen that the sampled distributors averaged **0.96%** annual MFP growth.[7] Output growth averaging **1.10**% annually outpaced multifactor input quantity growth averaging only **0.14**% annually. O&M and capital productivity each averaged **0.98**% annually.

Over the 2008-2011 period that is the focus of the B&V study, MFP growth was slower, averaging a slight **-0.07**% annual decline. Output growth fell substantially to only **0.38**% annually while multifactor input quantity growth rose modestly, averaging 0.45. O&M input growth --- which is characteristically volatile --- rose considerably whereas capital quantity growth fell modestly. The productivity of O&M inputs fell

[7] All growth trends in this report were included logarithmically.

Table 2a

Productivity Results For Sampled Gas Distributors

(Growth Rates)[1]

	Output Quantity	Input Quantities			Productivity		
Year		**O&M**	**Capital**	**Multifactor**	**O&M**	**Capital**	**Multifactor**
1998							
1999	1.88%	-0.90%	1.07%	0.29%	2.78%	0.81%	1.59%
2000	2.90%	4.00%	0.65%	2.50%	-1.10%	2.25%	0.40%
2001	1.28%	-3.94%	0.50%	-1.80%	5.22%	0.77%	3.08%
2002	0.91%	-4.86%	0.44%	-2.33%	5.77%	0.46%	3.23%
2003	2.15%	1.49%	0.65%	1.06%	0.66%	1.49%	1.09%
2004	1.02%	2.63%	0.11%	1.31%	-1.61%	0.91%	-0.29%
2005	1.32%	1.15%	-0.54%	0.35%	0.17%	1.86%	0.97%
2006	0.77%	-4.23%	-0.40%	-2.26%	5.00%	1.18%	3.03%
2007	0.56%	2.42%	-0.43%	0.96%	-1.86%	0.98%	-0.40%
2008	0.35%	-1.32%	-0.32%	-0.73%	1.67%	0.67%	1.08%
2009	0.31%	2.85%	-0.02%	1.41%	-2.54%	0.32%	-1.10%
2010	0.36%	1.52%	-0.03%	0.73%	-1.16%	0.39%	-0.37%
2011	0.51%	0.70%	-0.16%	0.39%	-0.19%	0.67%	0.12%
Average Annual Growth Rate							
1999-2011	**1.10%**	**0.12%**	**0.12%**	**0.14%**	**0.98%**	**0.98%**	**0.96%**
2008-2011	**0.38%**	**0.94%**	**-0.13%**	**0.45%**	**-0.56%**	**0.51%**	**-0.07%**

[1] All growth rates calculated logarthmically.

Table 2b

Productivity Results For Sampled Gas Distributors (Using 90% of Plant Additions)

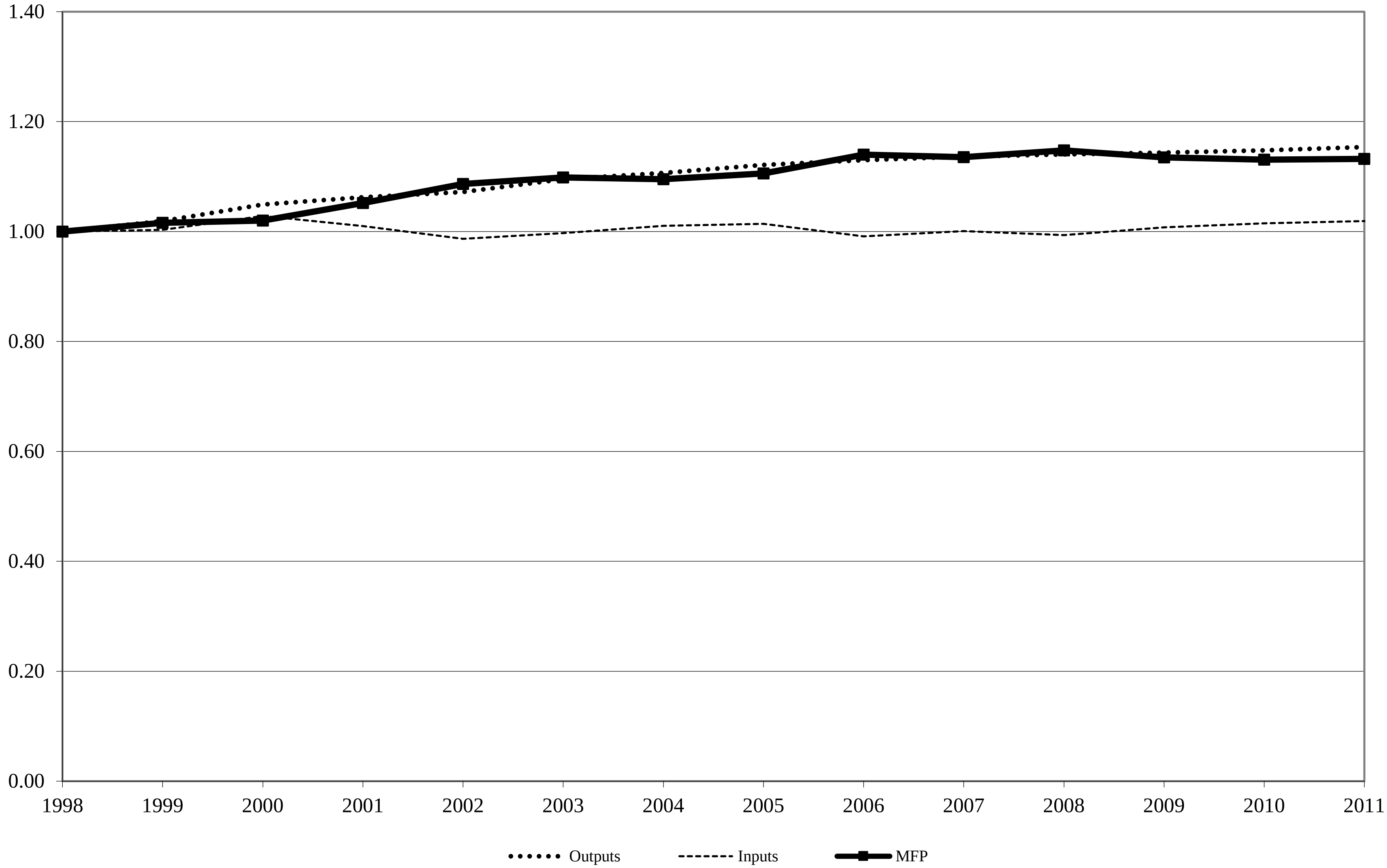
(Growth Rates)[1]

	Output Quantity	Input Quantities			Productivity		
Year		**O&M**	**Capital**	**Multifactor**	**O&M**	**Capital**	**Multifactor**
1998							
1999	1.88%	-0.90%	0.58%	0.04%	2.78%	1.30%	1.84%
2000	2.90%	4.00%	0.20%	2.31%	-1.10%	2.70%	0.59%
2001	1.28%	-3.94%	0.09%	-2.04%	5.22%	1.19%	3.32%
2002	0.91%	-4.86%	0.04%	-2.59%	5.77%	0.86%	3.49%
2003	2.15%	1.49%	0.25%	0.86%	0.66%	1.89%	1.28%
2004	1.02%	2.63%	-0.24%	1.16%	-1.61%	1.26%	-0.14%
2005	1.32%	1.15%	-0.85%	0.22%	0.17%	2.17%	1.10%
2006	0.77%	-4.23%	-0.72%	-2.46%	5.00%	1.49%	3.24%
2007	0.56%	2.42%	-0.73%	0.85%	-1.86%	1.29%	-0.29%
2008	0.35%	-1.32%	-0.62%	-0.90%	1.67%	0.97%	1.25%
2009	0.31%	2.85%	-0.32%	1.30%	-2.54%	0.63%	-1.00%
2010	0.36%	1.52%	-0.33%	0.61%	-1.16%	0.69%	-0.25%
2011	0.51%	0.70%	-0.44%	0.26%	-0.19%	0.95%	0.25%
Average Annual Growth Rate							
1999-2011	**1.10%**	**0.12%**	**-0.24%**	**-0.03%**	**0.98%**	**1.34%**	**1.13%**
2008-2011	**0.38%**	**0.94%**	**-0.43%**	**0.32%**	**-0.56%**	**0.81%**	**0.06%**

[1]All growth rates calculated logarthmically.

Figure 1

MFP TREND OF U.S. GAS DISTRIBUTORS



precipitously to a **0.56%** average annual decline. Capital productivity growth declined more modestly but remained positive, averaging **0.51%** annually.

Table 2b presents productivity results when 10% of plant additions have been removed. These results may be more pertinent considering that Fortis proposes to exclude a sizable share of its capex costs outside of the indexing mechanisms. Inspecting the results, it can be seen that over the full sample period the utilities averaged **1.13%** annual MFP growth. O&M productivity growth once again averaged **0.98%** annually while capital productivity growth was higher, averaging **1.34**% annually.

Table 3 and Figure 2 report the results of our gas distributor input price research.The multifactor input price indexes of the sampled gas utilities averaged **3.16%** annual growth. O&M prices averaged **2.89%** annual growth whereas capital prices averaged **3.43%** growth.

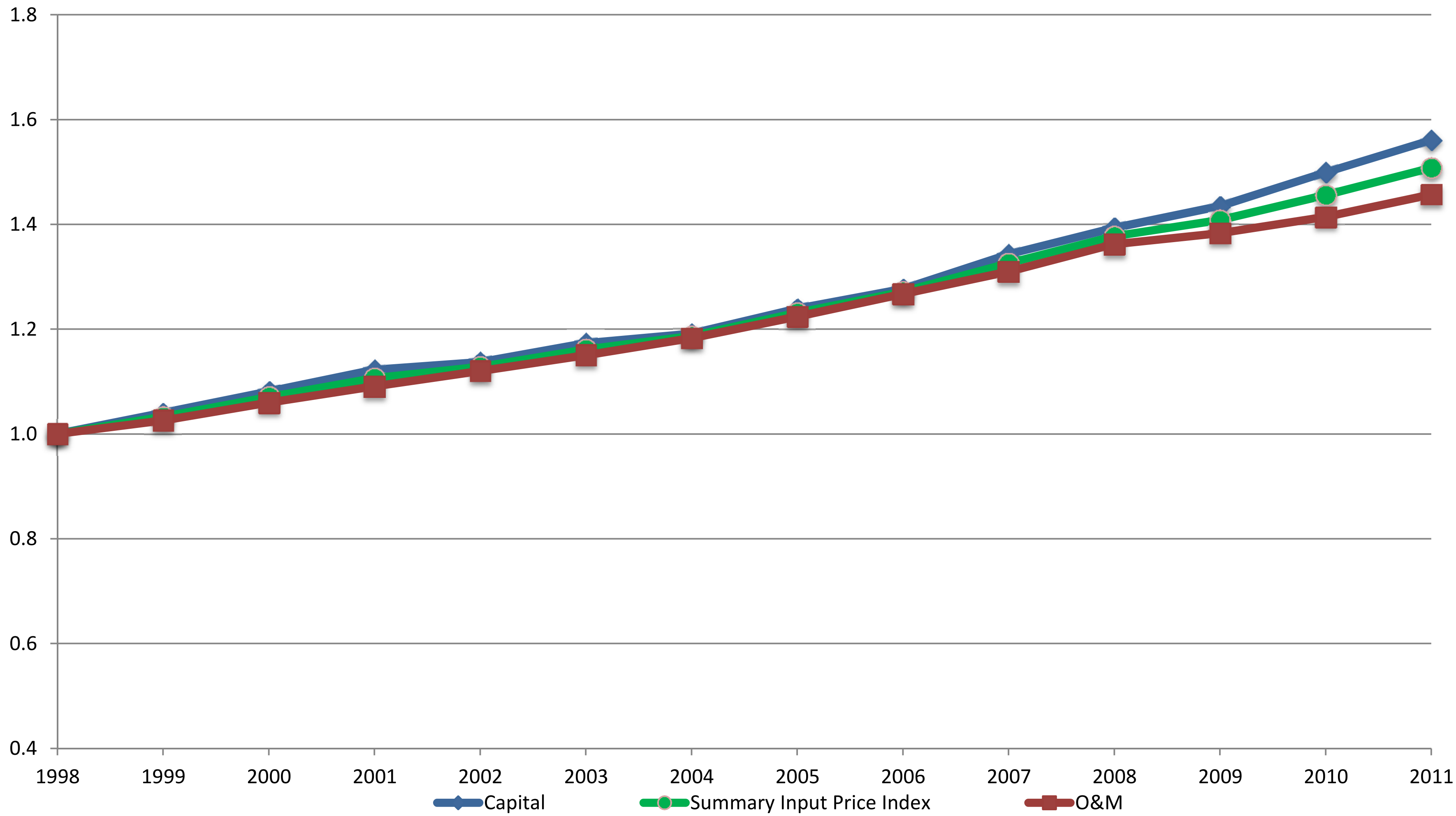
Table 3

Input Price Trends of U.S. Gas Distributors

	Input Price Subindexes				Summary Input Price Index	
	Capital[4]		O&M[2,3]			
	Index	Growth Rate[1]	Index	Growth Rate	Index	Growth Rate
1998	1.000		1.000		1.000	
1999	1.040	3.92%	1.026	2.55%	1.033	3.22%
2000	1.081	3.87%	1.060	3.25%	1.070	3.59%
2001	1.123	3.77%	1.091	2.89%	1.106	3.31%
2002	1.137	1.31%	1.120	2.65%	1.128	1.96%
2003	1.173	3.09%	1.150	2.65%	1.161	2.88%
2004	1.191	1.55%	1.183	2.80%	1.187	2.16%
2005	1.239	3.93%	1.224	3.40%	1.231	3.66%
2006	1.277	2.99%	1.267	3.49%	1.271	3.22%
2007	1.343	5.06%	1.310	3.30%	1.326	4.19%
2008	1.393	3.68%	1.362	3.92%	1.377	3.79%
2009	1.435	2.93%	1.383	1.52%	1.408	2.23%
2010	1.499	4.39%	1.414	2.24%	1.456	3.34%
2011	1.561	4.04%	1.457	2.96%	1.508	3.51%
Average Annual Growth Rates						
1999-2011		**3.43%**		**2.89%**		**3.16%**
2008-2011		**3.76%**		**2.66%**		**3.22%**

[1]All growth rates calculated logarthmically.
[2] Regionalized labor price indexes are calculated using US Bureau of Labor Statistics Employment Cost Indexes.
[3] M&S price index constructed from detailed price indexes for power distribution utility materials and services prepared by Global Insight.
[4]Capital price indexes calculated using cost of service (COS) formulas with construction cost indexes from Whitman, Requardt and Associates and rates of return on utility plant that are calculated using data from SNL Financial.

Figure 2
INPUT PRICE TRENDS OF SAMPLED GAS DISTRIBUTORS



4. Index Research: US Power Distribution

4.1 Data

The primary source of the cost and quantity data used in our power distribution index research was the FERC Form 1. Major investor-owned electric utilities in the United States are required by law to file this form annually. Cost and quantity data reported on Form 1 must conform to the FERC's Uniform System of Accounts. Details of these accounts can be found in Title 18 of the Code of Federal Regulations.

FERC Form 1 data are processed by the Energy Information Administration ("EIA") of the U.S. Department of Energy. Selected Form 1 data were for many years published by the EIA.[8] More recently, the data have been available electronically in raw form from the FERC and in more processed forms from commercial vendors. FERC Form 1 data used in this study were obtained from SNL Financial.

Data were eligible for inclusion in the sample from all major investor-owned electric utilities in the United States that filed the Form 1 electronically in 2001 and that, together with any important predecessor companies, have reported the necessary data continuously since they achieved a "major" designation. To be included in the study the data were required, additionally, to be of good quality and plausible. Data from 75 companies met these additional standards and were used in our indexing work. The data for these companies are the best available for rigorous work on input price and productivity trends to support the development of an X factor for FBC. The included companies are listed in Table 4.

A noteworthy idiosyncrasy of the FERC Form 1 is that it requests data on retail power *sales* volumes but not on the volumes of *unbundled distribution* services that might be provided under retail competition. Where retail competition exists, it complicates accurate calculation of trends in retail delivery volumes and customers. To rectify this shortcoming, we obtained our output data from Form EIA-861, the *Annual Electric Power Industry Report*. These data were also gathered by SNL Financial.

[8] This publication series had several titles over the years. A recent title is *Financial Statistics of Major U.S. Investor-Owned Electric Utilities.*

Table 4

Companies in PEG's Power Distribution Indexing Sample

Alabama Power
Appalachian Power
Arizona Public Service
Atlantic City Electric
Avista
Baltimore Gas & Electric
Bangor Hydro-Electric
Carolina Power & Light
Central Hudson Gas & Electric
Central Maine Power
Central Vermont Public Service
Cleveland Electric Illuminating
Connecticut Light & Power
Dayton Power & Light
Duke Energy Carolinas
Duke Energy Indiana
Duke Energy Ohio
Duquesne Light
El Paso Electric
Empire District Electric
Entergy Arkansas
Florida Power & Light
Florida Power
Georgia Power
Green Mountain Power
Gulf Power
Idaho Power
Indiana-Michigan Power
Indianapolis Power & Light
Jersey Central Power & Light
Kansas City Power & Light
Kansas Gas and Electric
Kentucky Power
Kentucky Utilities
Louisville Gas and Electric
Maine Public Service
Massachusetts Electric
Metropolitan Edison
Minnesota Power
Mississippi Power
Montana-Dakota Utilities
Narragansett Electric
Nevada Power
New York State Electric & Gas
Northern Indiana Public Service
Northern States Power-MN
Nstar Electric
Ohio Edison
Oklahoma Gas and Electric
Orange and Rockland Utilities
Pacific Gas and Electric
PacifiCorp
Pennsylvania Electric
Pennsylvania Power
Potomac Electric Power
Public Service of Colorado
Public Service of Oklahoma
Public Service Electric and Gas
Puget Sound Energy
San Diego Gas & Electric
South Carolina Electric & Gas
Southern California Edison
Southern Indiana Gas and Electric
Southwestern Public Service
Tampa Electric
Toledo Edison
Tucson Electric Power
United Illuminating
Virginia Electric and Power
West Penn Power
Western Massachusetts Electric
Western Resources
Wisconsin Electric Power
Wisconsin Power and Light
Wisconsin Public Service

Sample comprises 75 utilities

Other sources of data were also accessed in the research. These were used primarily to measure input price trends. As in our gas study, the supplemental data sources were Whitman, Requardt & Associates; Global Insight; and the BLS. The specific data drawn from these and the other sources mentioned are discussed further below.

4.2 Index Details

4.2.1 Scope

We calculated indexes of trends in the O&M, capital, and multifactor input prices and productivity of each sampled utility in the provision of power distributor services. The major tasks in a power distribution operation are the local delivery of power and the reduction in its voltage from the level at which it is received from the transmission network. [9] Most power is delivered to end users at the voltage at which it is consumed. Distributors also typically provide an array of customer services such as account, sales, and information services.

The total cost of power distribution considered in the study was the sum of applicable O&M expenses and capital costs. Itemized costs of any gas services provided by combined gas and electric utilities were excluded. We also excluded certain itemized costs that are unlikely to be subject to indexing in the PBR plan of FBC. The costs excluded for this reason included expenses for purchased power, power transmission by others, taxes, franchise fees, and pensions and other benefits. We excluded CSI and uncollectible bill expenses for the same reasons we discussed in Section 3.2.1.

Applicable O&M expenses included those reported for distribution, sales, and customer accounts (other than those for uncollectible bills), plus a sensible share of the company's administrative and general ("A&G") expenses (exclusive of those for pensions and benefits). A&G expenses are O&M expenses that are not readily assigned directly to particular operating functions under the Uniform System of Accounts. They include expenses incurred for injuries and damages, property insurance, regulatory proceedings, stockholder relations, and general advertising of the utility; the salaries and

[9] The term "distribution" in the Uniform System of Accounts corresponds most closely to local delivery service as here discussed.

wages of A&G employees, and the expenses for office supplies, rental services, outside services, and maintenance activities that are needed for general administration.

General plant is plant that is not directly assigned to particular operating functions in the Uniform System of Accounts. Certain structures and improvements (*e.g.* office buildings), communications equipment, office furniture and equipment, and transportation equipment account for the bulk of general plant value. Other general plant categories in the Uniform System of Accounts include tools, shop, and garage equipment, laboratory equipment, miscellaneous power-operated equipment, land and land rights, and stores equipment.

The index calculations required the breakdown of cost into four input categories: distribution plant, general plant, labor services, and M&S inputs. The cost of labor was defined for this purpose as salaries and wages. The cost of M&S inputs was defined as applicable O&M expenses net of these labor costs. The cost share for capital excluded taxes. The calculation of capital cost is discussed in Appendix Section 4.

4.2.2 Index Construction

The growth (rate) of each MFP index calculated in this study is the difference between the growth rates of indexes of industry output and input quantity trends. The growth of the output quantity index for the industry is the growth in the total number of customers served. The growth of the input quantity index is a weighted average of the growth in quantity subindexes for labor, materials and services, power distribution plant, and general plant. The growth of the input price index for the industry is a weighted average of the growth in price subindexes for these same input groups.

4.2.3 The Sample

The sample period was 2002-2011. The 2011 end date is the latest second to last year for which all data that we use to calculate the input price and MFP indexes are as yet available. The 2002 start date makes possible a ten-year average growth rate, and yet is recent enough to avoid most of the impact that power industry restructuring may have had on general costs.

4.3 INDEX RESULTS

Tables 5a and 5b and Figure 3 present key results of our productivity research. Inspecting 5a, it can be seen that over the full 2002-2011 sample period the annual average growth rate in the MFP of all sampled US power distributors was about **0.93**%. Output quantity growth averaged **0.87%** annually. Input quantity growth was close to zero, declining each year by a slight **-0.06%** on average. O&M productivity growth averaged **1.51%** annually whereas capital productivity growth averaged **0.61%** annually.

Over the 2008-2011 period that is the focus of the B&V study, the MFP growth of the full sample was only a little slower, averaging **0.90%** annually. O&M productivity growth accelerated modestly to a **1.72%** annual average whereas capital productivity growth slowed modestly to a **0.39%** average. The slowdown in capital productivity growth was not due to a surge in capital spending. In fact, capital quantity growth slowed modestly and was slightly negative during these years. The modest slowdown in capital productivity growth and acceleration of O&M productivity growth may reflect in part automated metering infrastructure capex that was encouraged by federal stimulus spending during these years.

Table 5b presents productivity results when 10% of plant additions have been removed. It can be seen that the sampled distributors averaged **1.18%** annual MFP growth. O&M productivity growth once again averaged **1.51%** annually but capital productivity growth accelerated, averaging **1.05**% annually.

Table 6 and Figure 4 report key findings of our power distributor input price research. Over the full sample period, the input prices facing sampled US power distributors were found to average about **3.13%** annual inflation. Labor price growth averaged **2.93%** annually whereas M&S price growth averaged **3.32%**. Distribution capital prices averaged **3.13%** growth whereas general capital prices averaged **2.84%** growth.

Table 5a

Productivity Results For Sampled Power Distributors

(Growth Rates)[1]

Year	Output Quantity	Input Quantities			Productivity		
		O&M	Capital	Multifactor	O&M	Capital	Multifactor
2001							
2002	1.22%	-0.34%	0.42%	0.16%	1.56%	0.81%	1.07%
2003	1.26%	2.86%	0.52%	1.58%	-1.60%	0.73%	-0.33%
2004	1.22%	-4.41%	0.38%	-1.61%	5.62%	0.83%	2.83%
2005	1.45%	-0.57%	0.37%	0.02%	2.03%	1.08%	1.43%
2006	1.12%	0.06%	0.70%	0.53%	1.06%	0.42%	0.58%
2007	1.11%	1.53%	0.43%	0.97%	-0.42%	0.68%	0.14%
2008	0.53%	-2.70%	0.31%	-1.09%	3.23%	0.22%	1.62%
2009	0.24%	-2.25%	0.05%	-0.66%	2.49%	0.19%	0.90%
2010	0.36%	1.35%	-0.47%	0.41%	-0.99%	0.84%	-0.05%
2011	0.17%	-1.97%	-0.15%	-0.95%	2.14%	0.32%	1.12%
Average Annual Growth Rates							
2002-2011	**0.87%**	**-0.64%**	**0.26%**	**-0.06%**	**1.51%**	**0.61%**	**0.93%**
2008-2011	**0.33%**	**-1.39%**	**-0.07%**	**-0.57%**	**1.72%**	**0.39%**	**0.90%**

[1]All growth rates calculated logarthmically.

Table 5b

Productivity Results For Sampled Power Distributors
(Using 90% of Plant Additions)

(Growth Rates)[1]

Year	Output Quantity	Input Quantities			Productivity		
		O&M	Capital	Multifactor	O&M	Capital	Multifactor
2001							
2002	1.22%	-0.34%	-0.08%	-0.13%	1.56%	1.31%	1.35%
2003	1.26%	2.86%	0.04%	1.32%	-1.60%	1.22%	-0.06%
2004	1.22%	-4.41%	-0.11%	-1.91%	5.62%	1.32%	3.13%
2005	1.45%	-0.57%	-0.09%	-0.24%	2.03%	1.54%	1.69%
2006	1.12%	0.06%	0.23%	0.27%	1.06%	0.88%	0.85%
2007	1.11%	1.53%	-0.01%	0.74%	-0.42%	1.12%	0.37%
2008	0.53%	-2.70%	-0.11%	-1.35%	3.23%	0.64%	1.88%
2009	0.24%	-2.25%	-0.34%	-0.90%	2.49%	0.58%	1.14%
2010	0.36%	1.35%	-0.82%	0.24%	-0.99%	1.18%	0.13%
2011	0.17%	-1.97%	-0.49%	-1.17%	2.14%	0.66%	1.34%
Average Annual Growth Rates							
2002-2011	**0.87%**	**-0.64%**	**-0.18%**	**-0.31%**	**1.51%**	**1.05%**	**1.18%**
2008-2011	**0.33%**	**-1.39%**	**-0.44%**	**-0.79%**	**1.72%**	**0.77%**	**1.12%**

[1]All growth rates calculated logarthmically.

Figure 3

MFP TREND OF U.S. POWER DISTRIBUTORS

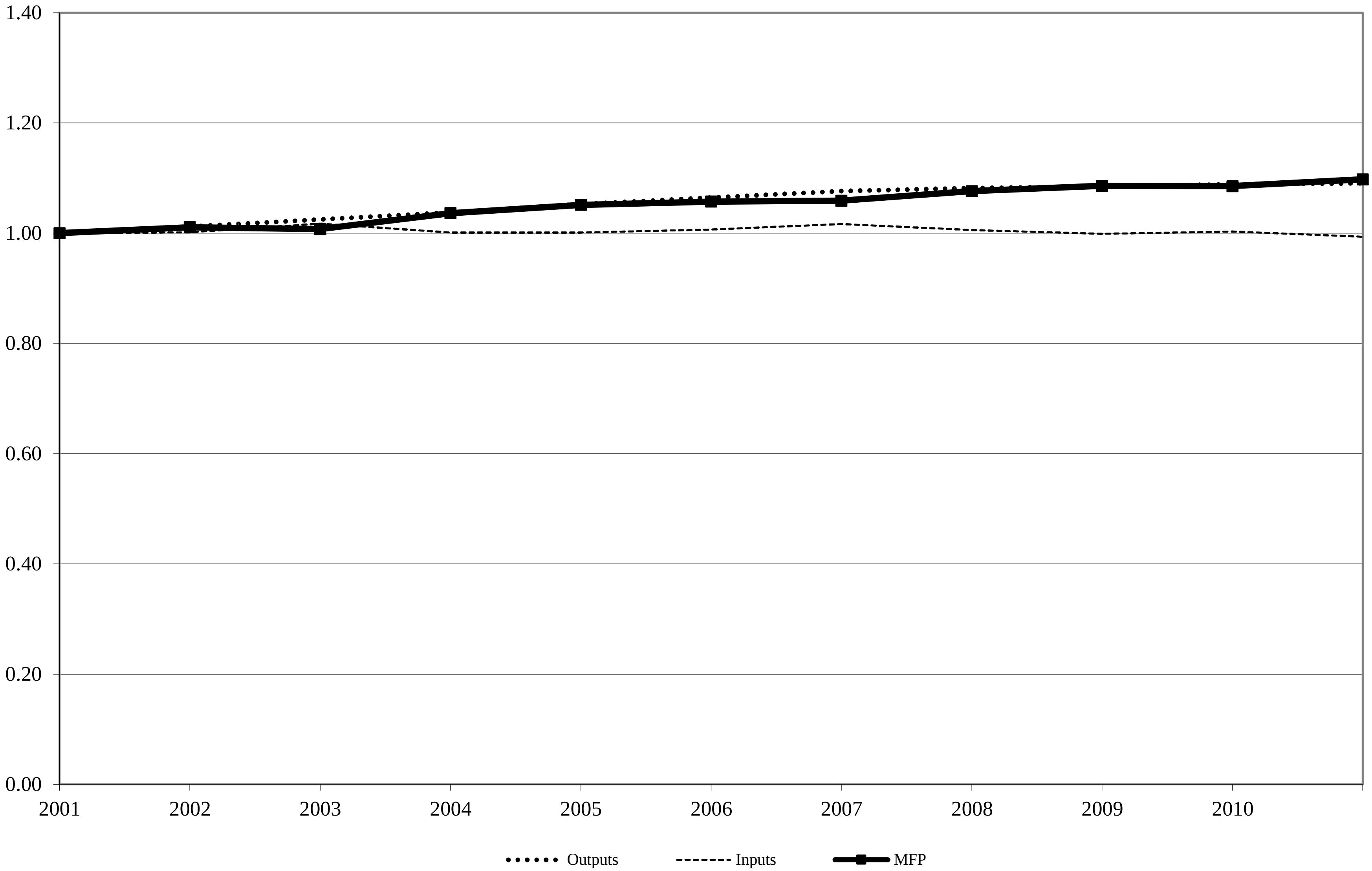


Table 6

Input Price Trends of Sampled Power Distributors

	Input Price Subindexes								Summary Input Price Index	
	Distribution Capital[3]		General Capital[3]		Labor O&M[1]		Materials & Services[2]			
	Index	Growth[4]	Index	Growth	Index[1]	Growth	Index[2]	Growth	Index	Growth
2001	1.000		1.000		1.000		1.000		1.000	
2002	1.015	1.50%	1.028	2.74%	1.036	3.58%	1.017	1.64%	1.020	1.94%
2003	1.049	3.33%	1.066	3.64%	1.064	2.66%	1.045	2.72%	1.051	3.06%
2004	1.066	1.52%	1.095	2.68%	1.097	3.00%	1.085	3.79%	1.077	2.40%
2005	1.095	2.75%	1.135	3.63%	1.127	2.69%	1.137	4.68%	1.112	3.25%
2006	1.137	3.76%	1.175	3.40%	1.162	3.09%	1.193	4.85%	1.157	3.89%
2007	1.176	3.34%	1.207	2.72%	1.199	3.15%	1.240	3.79%	1.196	3.37%
2008	1.219	3.62%	1.247	3.26%	1.238	3.15%	1.306	5.24%	1.244	3.92%
2009	1.272	4.24%	1.266	1.49%	1.273	2.80%	1.312	0.43%	1.282	2.96%
2010	1.326	4.15%	1.298	2.53%	1.305	2.47%	1.341	2.22%	1.325	3.32%
2011	1.368	3.13%	1.329	2.33%	1.341	2.74%	1.394	3.87%	1.368	3.20%
Average Annual Growth Rates										
2002-2011		**3.13%**		**2.84%**		**2.93%**		**3.32%**		**3.13%**
2008-2011		**3.79%**		**2.40%**		**2.79%**		**2.94%**		**3.35%**

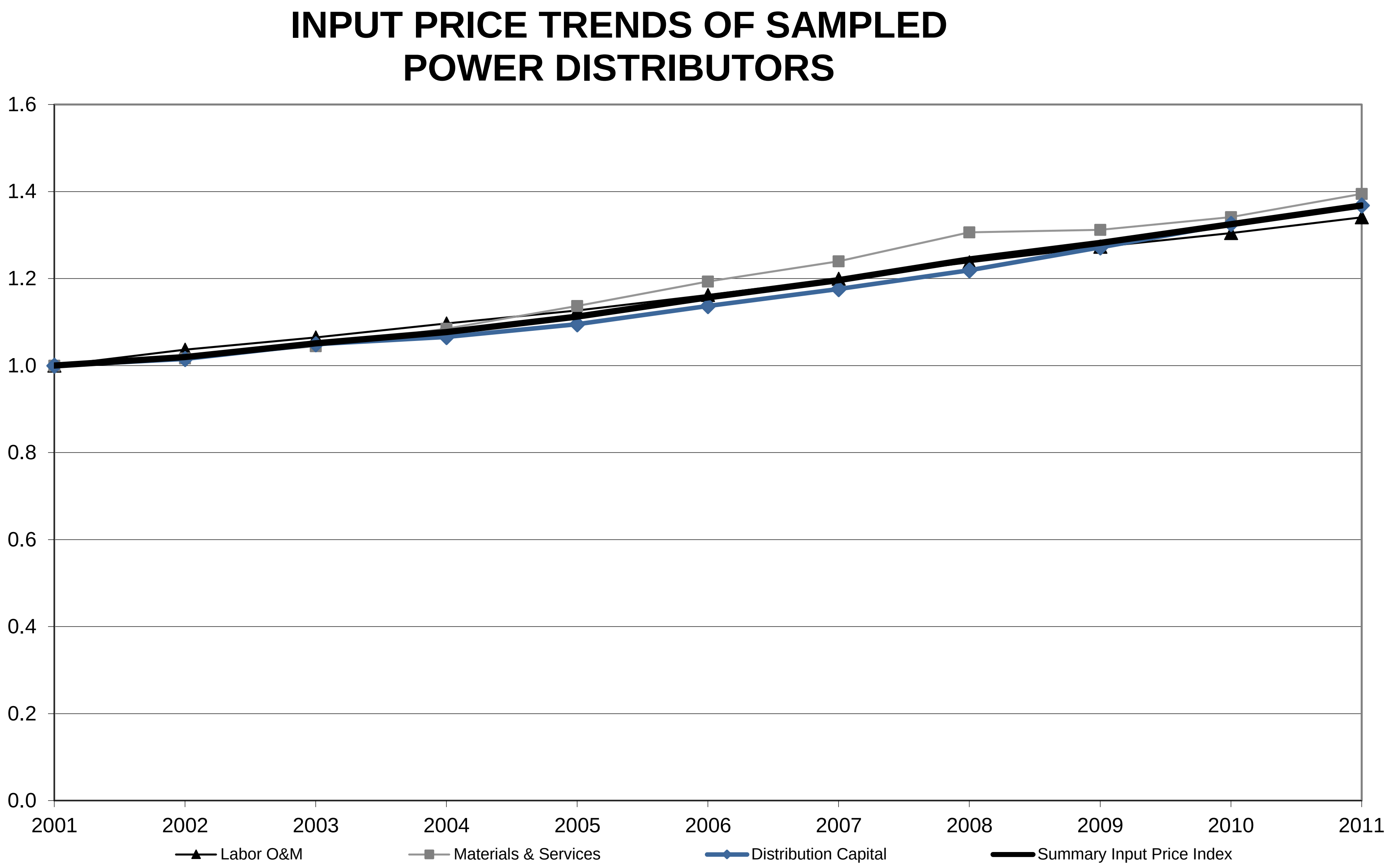
[1] Regionalized labor price indexes are calculated using US Bureau of Labor Statistics Employment Cost Indexes.

[2] M&S price index constructed from detailed price indexes for power distribution utility materials and services prepared by Global Insight.

[3] Capital price indexes calculated using cost of service (COS) formulas with construction cost indexes from Whitman, Requardt and Associates and rates of return on utility plant that are calculated using data from SNL Financial.

[4] All growth rates calculated logarthmically.

Figure 4


INPUT PRICE TRENDS OF SAMPLED POWER DISTRIBUTORS
1.6
1.4
1.2
1.0
0.8
0.6
0.4
0.2
0.0
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
Labor O&M
Materials & Services
Distribution Capital
Summary Input Price Index

5. CANADIAN PRICE RESEARCH

5.1 MACROECONOMIC PRICE INDEXES

We noted in Section 2.2.5 that macroeconomic output price indexes pose fewer complications in the design of an ARM in Canada than they do in the United States. The chief reason is that the productivity trend of the Canadian economy is close to zero. Macroeconomic price indexes also merit consideration as a subindex in an industry-specific input price index.

Table 7 shows the trends in seven macroeconomic output price indexes that are sensible candidates for use in BC.[10] Here are the indexes with a brief discussion of noteworthy features.

- The CPI for Canada is the inflation measure most familiar to Canadian consumers. This type of inflation measure is the norm in British and Australian MRPs. It is less common in North America, where there is greater interest in the ability of an inflation measure to track utility input price trends. The CPI places a fairly heavy weight on price-volatile consumer commodities like gasoline, natural gas, and food. These commodities make the CPI more volatile and have much more impact on the budget of a typical consumer than they do on the cost of an energy distributor's base rate inputs. CPIs also have the characteristic of not being revised.
- The CPI for BC ("CPI^{BC}") has the drawbacks just noted for the CPI but is specific to the province. It should therefore be more sensitive to local inflation conditions than the national CPI.
- The core CPI (CPI^{core}) excludes inflation in the prices of price-volatile commodities such as gasoline and food. It is available for Canada but not for BC.
- GDP implicit price indexes ("GDPIPIs") track inflation in the prices of capital equipment, government services, and net exports as well as consumer

[10] Some of the annual averages in Tables 7, 8 and 9 were incorrectly tabulated in our initial filing. The corrected averages are shaded in the tables in this errata filing.

Table 7

Macroeconomic Inflation Measures for BC and Canada

	Canada								British Columbia					
	CPI (all items)[1]		Core CPI[1 2]		GDPIPIs[3]				CPI (all items)[1]		GDPIPIs[3]			
					Comprehensive		Final Domestic Demand				Comprehensive		Final Domestic Demand	
Year	Level	Growth Rate[4]	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate
1982	54.9				51.8	8.1%	53.2	9.1%	57.3		48.6	6.7%	53.1	8.7%
1983	58.1	5.7%			54.6	5.3%	56.1	5.3%	60.4	5.3%	50.9	4.6%	55.6	4.7%
1984	60.6	4.2%	62.9		56.4	3.2%	58.3	4.0%	62.8	3.9%	53.1	4.1%	57.6	3.5%
1985	63.0	3.9%	65.1	3.4%	58.1	3.0%	60.4	3.5%	64.8	3.1%	53.3	0.3%	58.8	2.2%
1986	65.6	4.0%	68.0	4.4%	59.9	3.1%	62.7	3.7%	66.7	2.9%	56.2	5.3%	60.8	3.3%
1987	68.5	4.3%	71.0	4.3%	62.6	4.5%	65.2	4.0%	68.7	3.0%	58.5	4.0%	62.6	2.9%
1988	71.2	3.9%	74.0	4.1%	65.5	4.4%	67.7	3.7%	71.2	3.6%	61.4	4.9%	64.8	3.4%
1989	74.8	4.9%	77.2	4.2%	68.4	4.4%	70.6	4.2%	74.4	4.4%	64.7	5.3%	67.9	4.6%
1990	78.4	4.7%	79.8	3.3%	70.6	3.2%	73.3	3.8%	78.4	5.2%	67.0	3.4%	70.9	4.4%
1991	82.8	5.5%	82.1	2.8%	72.7	2.9%	75.8	3.4%	82.6	5.2%	69.0	3.0%	73.6	3.6%
1992	84.0	1.4%	83.6	1.8%	73.6	1.3%	77.1	1.7%	84.8	2.6%	71.7	3.8%	75.9	3.1%
1993	85.6	1.9%	85.3	2.0%	74.7	1.5%	78.6	2.0%	87.8	3.5%	74.0	3.2%	78.2	3.0%
1994	85.7	0.1%	86.9	1.9%	75.6	1.1%	79.8	1.5%	89.5	1.9%	76.9	3.9%	80.2	2.5%
1995	87.6	2.2%	88.8	2.2%	77.3	2.2%	80.8	1.2%	91.6	2.3%	78.9	2.6%	81.8	1.9%
1996	88.9	1.5%	90.3	1.7%	78.5	1.5%	81.7	1.1%	92.4	0.9%	79.4	0.5%	82.6	1.0%
1997	90.4	1.7%	92.0	1.9%	79.4	1.2%	82.9	1.4%	93.1	0.8%	80.8	1.8%	83.6	1.2%
1998	91.3	1.0%	93.2	1.3%	79.1	-0.4%	84.0	1.3%	93.4	0.3%	80.7	-0.2%	84.4	1.0%
1999	92.9	1.7%	94.5	1.4%	80.5	1.7%	85.1	1.3%	94.4	1.1%	81.7	1.3%	85.1	0.9%
2000	95.4	2.7%	95.7	1.3%	83.8	4.1%	87.0	2.3%	96.1	1.8%	84.8	3.8%	86.7	1.9%
2001	97.8	2.5%	97.7	2.1%	84.7	1.1%	88.6	1.8%	97.7	1.7%	85.7	1.0%	88.1	1.5%
2002	100.0	2.2%	100.0	2.3%	85.7	1.1%	90.6	2.2%	100.0	2.3%	85.6	-0.1%	90.3	2.4%
2003	102.8	2.8%	102.2	2.2%	88.5	3.2%	91.9	1.5%	102.2	2.2%	88.2	3.0%	91.6	1.5%
2004	104.7	1.8%	103.8	1.6%	91.3	3.1%	93.5	1.7%	104.2	1.9%	92.1	4.4%	93.3	1.9%
2005	107.0	2.2%	105.5	1.6%	94.3	3.2%	95.6	2.2%	106.3	2.0%	94.6	2.7%	95.0	1.8%
2006	109.1	1.9%	107.5	1.9%	96.8	2.6%	97.7	2.2%	108.1	1.7%	97.7	3.2%	97.7	2.8%
2007	111.5	2.2%	109.8	2.1%	100.0	3.2%	100.0	2.3%	110.0	1.7%	100.0	2.3%	100.0	2.3%
2008	114.1	2.3%	111.7	1.7%	103.9	3.8%	102.5	2.5%	112.3	2.1%	102.3	2.3%	102.3	2.3%
2009	114.4	0.3%	113.6	1.7%	101.7	-2.1%	103.7	1.2%	112.3	0.0%	100.9	-1.4%	103.5	1.2%
2010	116.5	1.8%	115.6	1.7%	104.4	2.6%	104.8	1.1%	113.8	1.3%	102.7	1.8%	104.5	1.0%
2011	119.9	2.9%	117.5	1.6%	107.7	3.1%	107.3	2.4%	116.5	2.3%	104.5	1.7%	106.3	1.7%
2012	121.7	1.5%	119.5	1.7%	109.5	1.7%	109.2	1.8%	117.8	1.1%	105.3	0.8%	107.6	1.2%
Average Annual Growth Rates														
1983-2012		**2.7%**		**NA**		**2.5%**		**2.4%**		**2.4%**		**2.6%**		**2.36%**
1983-1992		**4.25%**		**NA**		**3.52%**		**3.71%**		**3.92%**		**3.88%**		**3.58%**
1993-2002		**1.74%**		**1.79%**		**1.52%**		**1.61%**		**1.65%**		**1.78%**		**1.73%**
2003-2012		**1.96%**		**1.78%**		**2.45%**		**1.87%**		**1.64%**		**2.07%**		**1.76%**
2008-2012		**1.75%**		**1.69%**		**1.82%**		**1.76%**		**1.37%**		**1.03%**		**1.47%**
Standard Deviation														
1987-2012		**1.33%**		**0.88%**		**1.55%**		**0.94%**		**1.33%**		**1.65%**		**1.06%**

Footnotes
[1] Statistics Canada. Table 326-0021 - Consumer Price Index (CPI), 2009 basket, annual.

[2] The Core CPI excludes volatile components of the all items CPI: fruit, fruit preparations and nuts; vegetables and vegetable preparations; mortgage interest cost; natural gas; fuel oil and other fuels; gasoline; inter-city transportation; and tobacco

[3] Statistics Canada. Table 384-0036 (1981-2006) and Table 384-0039 (2007-2012) - Implicit price indexes, gross domestic product (GDP), provincial economic accounts, annual (index, 2007=100).

[4] All growth rates are calculated logarithmically.

Notes:
- Annual CPI data become available for the previous year near the end of January of the following year (e.g. Annual 2012 data became available on 1/25/2013).
- Annual CPI data are not revised. Monthly CPI is released during the third week of the following month.
- GDPIPI data are revised periodically as improved data sources and/or methodology become available.
- "NA" is defined as "Not available."

products. They are periodically updated and are available for BC as well as Canada. In the United States, a GDPPI is often preferred over the CPI in PBR plans because the impact of price-volatile consumer commodities is watered down. In Canada's economy, with its sizable reliance on natural resource exports, this stabilizing benefit is offset, however, by fluctuations in the prices of exports.

- GDPIPIs for final domestic demand ("GDPIPI^{FDD}s") exclude the inflation impact of exports. They are available for BC as well as Canada. They have been used several times as inflation measures for PBR plans in Ontario. In contrast to the other inflation measures discussed here, forecasts of provincial GDPIPI$^{FDD}{}_{s}$ are not readily available.

Inspecting the numbers in Table 7 it can be seen that these indexes vary considerably in their volatility, which is measured in the bottom row of the table by the standard deviation of their growth rates. The CPIs and comprehensive GDPIPIs for Canada and BC are considerably more volatile than the core CPI or the GDPIPIs for final domestic demand. In 2009, for instance, the CPI (all items) for Canada and BC grew only 0.3% and 0.0%, while the comprehensive GDPIPIs for Canada and BC *fell* by 2.1% and 1.4%. In the same year, the core CPI grew by 1.7% and the GDPIPI^{FDD}s for Canada and BC both grew by 1.2%. The trends in Canada's core CPI and the GDPIPI^{FDD} are quite similar, as we might expect.

Comparisons between BC and Canadian price indexes are also instructive. For both the CPI and the GDPIPI^{FDD}, inflation in BC has tended to be somewhat slower than that in Canada. This is an argument for the use of a BC-specific macroeconomic inflation measures in applications to FBC and FEI.

5.2 Custom Input Price Indexes

Suppose, now, that the Comission prefers utility-specific input price indexes as ARM inflation measures. Fortis has proposed a simple index of this kind called a "composite I-factor" for all of its cost indexes. It would average estimated inflation in price subindexes for labor and non-labor inputs. The proposed labor price subindex is the

Average Weekly Earnings ("AWE") for BC. The proposed subindex for other inputs is the CPI^{BC}.

A 55% weight is proposed for the labor price. For FEI, this weight is explained as the share of "labor-related costs" in 2012 non-fuel O&M expenses. FBC forecasted the share of "labor-related costs" in some cost metric 2014-2018.

Table 8 presents alternative Canadian and BC indexes of salary and wage prices that are available for an industry-specific input price index. Fixed weighted indices of the average hourly earnings ("AHE") of all employees in BC have the advantage of being expressly designed to measure labor price *trends.* The average weekly earnings (AWE) for BC is not, and is therefore prone to some aggregation bias as the composition of the labor force changes. However, the AWE covers a somewhat broader range of workers (*e.g.* those whose basic remuneration is not in the form of a wage rate or a salary but rather an alternative such as commissions and piece rates).

Considering the results in Tables 7 and 8, it can be seen that the trends in the AWE and AHE are quite similar. Both indexes have tended to grow a little more slowly in BC than in Canada as a whole. This is an argument for use of a BC-specific labor price index if one is to be featured in PBR inflation measures.

It is also noteworthy that inflation in all of the labor price indexes tends to rise a good bit more rapidly than the corresponding macroeconomic inflation indexes detailed in the prior table. From 2003-2012, for instance, the AWE averaged 2.6% annual growth whereas the CPI^{BC} averaged only 1.64% annual growth. Fortis therefore benefits from having a large labor cost share in its inflation measure.

Tables 9, 10, and 11 present three groups of indexes maintained by Statistics Canada that could serve as capex price indexes for the Fortis companies.

- Summary electric utility construction price indexes ("EUCPIs") for power distribution and transmission
- Capital stock price indexes ("CSPIs") for natural gas distribution, water, and other systems[11]
- Non-residential building construction price indexes.

[11] The CSPI for non-information and communication technologies machinery and equipment was incorrectly stated in our initial filing. The correct index and annual averages are shaded in the table of this errata filing.

Table 8

Salary and Wage Price Indexes for BC and Canada

Year	Fixed weighted index of average hourly earnings (AHE) for all employees[1 2]								Average weekly earnings (AWE) for all employees (Industrial aggregate excluding unclassified businesses)[2 3]				Composite construction union wage rate index[4]		
	Canada				British Columbia				Canada		British Columbia				
	Industrial Aggregate	Growth Rate[5]	Utilities	Growth Rate	Industrial Aggregate	Growth Rate	Utilities	Growth Rate	Level	Growth Rate	Level	Growth Rate	Canada	Vancouver	Victoria
1982													43.7	50.7	53.8
1983													49.2	56.5	60.0
1984													51.0	58.1	61.6
1985													52.2	59.8	63.4
1986													53.7	60.6	64.3
1987													55.2	60.6	64.3
1988													57.2	63.0	66.8
1989													59.9	66.6	70.5
1990													63.2	69.8	73.6
1991													67.0	73.7	78.1
1992													70.1	77.4	81.8
1993													71.7	79.9	83.5
1994													73.2	80.6	83.9
1995													74.6	83.2	85.4
1996													75.2	84.4	87.0
1997													76.8	84.9	88.6
1998													78.4	85.1	89.3
1999													79.7	85.1	89.3
2000													81.8	85.1	89.3
2001	98.0		94.9		98.5		94.5		656.55		656.89		83.8	85.4	89.5
2002	100.2	2.22%	99.9	5.13%	100.3	1.81%	100.0	5.66%	672.52	2.40%	670.64	2.07%	87.0	85.9	89.9
2003	103.1	2.85%	105.1	5.07%	102.9	2.56%	104.9	4.78%	690.64	2.66%	685.19	2.15%	89.3	86.4	90.3
2004	105.9	2.68%	107.0	1.79%	105.2	2.21%	110.6	5.29%	709.08	2.63%	696.95	1.70%	91.4	86.5	90.4
2005	109.3	3.16%	108.9	1.76%	108.2	2.81%	116.3	5.03%	737.01	3.86%	722.38	3.58%	94.1	87.3	90.5
2006	112.1	2.53%	111.2	2.09%	111.3	2.82%	122.5	5.19%	755.21	2.44%	743.57	2.89%	97.0	94.6	95.2
2007	117.3	4.53%	117.4	5.43%	115.7	3.88%	126.4	3.13%	787.73	4.22%	768.89	3.35%	100.0	100.0	100.0
2008	121.4	3.44%	118.9	1.27%	120.1	3.73%	125.9	-0.40%	810.47	2.85%	788.55	2.52%	104.9	104.6	104.4
2009	125.1	3.00%	125.8	5.64%	123.1	2.47%	132.7	5.26%	823.16	1.55%	795.15	0.83%	109.2	108.8	108.7
2010	128.9	2.99%	129.8	3.13%	124.5	1.13%	136.6	2.90%	852.95	3.56%	819.11	2.97%	112.6	111.6	111.5
2011	131.5	2.00%	131.8	1.53%	127.1	2.07%	141.2	3.31%	874.31	2.47%	841.74	2.73%	115.4	112.8	112.6
2012	134.2	2.03%	135.6	2.84%	130.0	2.26%	144.2	2.10%	896.81	2.54%	866.31	2.88%	118.2	115.6	115.6
Average Annual Growth Rates															
2003-2012		**2.9%**		**3.1%**		**2.6%**		**3.7%**		**2.9%**		**2.6%**	**3.1%**	**3.0%**	**2.5%**
2008-2012		**2.7%**		**2.9%**		**2.3%**		**2.6%**		**2.6%**		**2.4%**	**3.3%**	**2.9%**	**2.9%**

Footnotes

[1] Statistics Canada. Table 281-0039 - Fixed weighted index of average hourly earnings for all employees (SEPH), excluding overtime, unadjusted for seasonal variation. Available for selected industries classified using the North American Industry Classification System (NAICS), monthly (index, 2002=100)

[2] Industrial aggregate covers all industrial sectors except those primarily involved in agriculture, fishing and trapping, private household services, religious organisations, and the military personnel of the defense services.

[3] Statistics Canada. Table 281-0027 - Average weekly earnings (SEPH), unadjusted for seasonal variation. Available by type of employee for selected industries classified using the North American Industry Classification System (NAICS), annual (current dollars)

[4] Statistics Canada. Table 327-0045 - Construction union wage rate indexes, annual (index, 2007=100). Construction union wage rate indexes including selected pay supplement

[5] All growth rates are calculated logarithmically.

Notes

• Payroll employment, earnings and hours data are released on a monthly basis. Data are released near the end of each month for the month two months prior (e.g. Dec 2013 data will be released near the end of Feb 2014).

Table 9

Canadian Electric Utility Construction Price Indexes

	Distribution Systems							Transmission Systems	
	Total							Total	
Year	Level	Growth Rate[1]	Total direct costs	Materials	Labour	Construction equipment	Construction indirects	Level	Growth Rate
1956	17.7				8.3	17.3		20.0	
1957	18.0	1.7%			8.6	18.3		20.6	3.0%
1958	17.4	-3.4%			9.3	19.0		19.5	-5.5%
1959	18.1	3.9%			9.8	24.7		20.1	3.0%
1960	18.7	3.3%			10.4	20.0		19.8	-1.5%
1961	18.7	0.0%			10.9	20.3		18.6	-6.3%
1962	19.0	1.6%			11.4	20.0		19.3	3.7%
1963	19.1	0.5%			11.9	20.2		19.7	2.1%
1964	19.5	2.1%			12.3	20.4		20.4	3.5%
1965	19.9	2.0%			12.9	20.5		21.4	4.8%
1966	20.9	4.9%			13.5	20.9	14.5	22.3	4.1%
1967	21.7	3.8%			15.1	22.0	15.6	22.5	0.9%
1968	21.5	-0.9%			16.2	22.5	16.8	22.2	-1.3%
1969	22.4	4.1%			17.5	23.3	18.1	22.9	3.1%
1970	24.1	7.3%			18.9	24.7	19.6	25.0	8.8%
1971	25.0	3.7%	25.6	29.8	20.3	26.0	21.2	26.1	4.3%
1972	26.1	4.3%	26.6	30.0	22.1	26.9	23.2	27.3	4.5%
1973	28.5	8.8%	29.1	32.6	25.0	27.9	24.7	29.3	7.1%
1974	34.3	18.5%	35.6	42.3	27.4	32.0	27.7	35.5	19.2%
1975	38.5	11.6%	39.7	45.7	32.5	34.8	31.9	41.6	15.9%
1976	40.7	5.6%	41.7	45.5	37.2	39.1	35.2	44.6	7.0%
1977	43.4	6.4%	44.4	46.7	41.4	43.3	38.3	47.0	5.2%
1978	46.6	7.1%	47.7	50.3	44.2	48.3	41.0	50.6	7.4%
1979	52.9	12.7%	54.5	60.3	47.0	54.2	44.5	56.5	11.0%
1980	60.3	13.1%	62.3	70.6	51.6	61.7	49.4	63.3	11.4%
1981	65.7	8.6%	67.8	75.0	57.5	74.0	55.2	69.7	9.6%
1982	71.8	8.9%	73.7	79.9	64.5	82.1	62.3	75.1	7.5%
1983	74.8	4.1%	76.2	79.1	71.0	86.2	67.2	77.0	2.5%
1984	78.1	4.3%	79.4	83.0	73.6	88.9	70.9	80.6	4.6%
1985	82.1	5.0%	83.7	88.7	76.0	93.0	74.1	81.6	1.2%
1986	84.0	2.3%	85.5	90.7	78.0	90.4	76.5	84.0	2.9%
1987	86.6	3.0%	87.9	93.3	80.7	91.3	79.5	89.2	6.0%
1988	91.9	5.9%	93.6	101.7	83.6	89.5	83.0	96.5	7.9%
1989	95.5	3.8%	97.3	105.0	88.0	91.9	85.7	102.6	6.1%
1990	98.5	3.1%	99.9	106.9	91.3	97.2	90.8	104.0	1.4%
1991	97.7	-0.8%	97.9	98.5	96.9	99.4	96.8	100.4	-3.5%
1992	100.0	2.3%	100.0	100.0	100.0	100.0	100.0	100.0	-0.4%
1993	102.5	2.5%	102.5	102.1	102.7	104.8	102.3	103.0	3.0%
1994	108.2	5.4%	109.1	112.5	104.3	111.0	103.3	108.1	4.8%
1995	116.7	7.6%	118.7	128.1	106.1	120.3	105.5	112.8	4.3%
1996	116.6	-0.1%	118.2	126.1	106.6	125.7	107.9	113.5	0.6%
1997	118.0	1.2%	119.3	125.0	110.1	129.8	111.1	115.7	1.9%
1998	122.8	4.0%	123.0	125.4	117.6	138.1	121.4	121.0	4.5%
1999	126.1	2.7%	126.0	126.0	123.6	141.5	126.9	122.2	1.0%
2000	128.7	2.0%	129.1	128.6	128.8	135.3	126.7	124.7	2.0%
2001	129.6	0.7%	129.8	127.7	130.7	142.0	128.9	127.0	1.8%
2002	130.5	0.7%	130.6	127.6	132.3	145.5	129.9	129.2	1.7%
2003	130.6	0.1%	130.9	127.8	132.7	145.5	129.0	126.4	-2.2%
2004	131.1	0.4%	131.3	132.5	127.2	148.0	129.9	129.0	2.0%
2005	133.6	1.9%	134.2	138.2	125.3	157.7	130.4	130.9	1.5%
2006	142.4	6.4%	144.2	155.0	127.5	160.0	132.6	136.2	4.0%
2007	148.8	4.4%	150.7	165.0	130.3	160.0	138.4	142.6	4.6%
2008	150.3	1.0%	151.9	167.6	127.7	173.8	141.4	148.8	4.3%
2009	151.1	0.5%	150.7	167.5	127.2	159.1	153.4	149.7	0.6%
2010	155.1	2.6%	155.2	169.6	134.8	163.5	154.7	150.5	0.5%
2011	160.1	3.2%	159.5	170.9	143.4	166.3	162.9	154.0	2.3%
2012	161.4	0.8%	160.7	170.7	147.1	163.3	164.8	154.3	0.2%
2013	159.1	-1.4%	158.4	171.7	140.0	163.4	162.8	155.1	0.5%
Average Annual Growth Rates									
1969-2008		**4.9%**	**NA**	**NA**	**5.2%**	**5.1%**	**5.3%**		**4.8%**
1979-2008		**3.9%**	**3.9%**	**4.0%**	**3.5%**	**4.3%**	**4.1%**		**3.6%**
1989-2008		**2.5%**	**2.4%**	**2.5%**	**2.1%**	**3.3%**	**2.7%**		**2.2%**
1999-2008		**2.0%**	**2.1%**	**2.9%**	**0.8%**	**2.3%**	**1.5%**		**2.1%**
1984-2013		**2.5%**	**2.4%**	**2.6%**	**2.3%**	**2.1%**	**2.9%**		**2.3%**
1994-2013		**2.2%**	**2.2%**	**2.6%**	**1.5%**	**2.2%**	**2.3%**		**2.0%**
2004-2013		**2.0%**	**1.9%**	**3.0%**	**0.5%**	**1.2%**	**2.3%**		**2.0%**

Footnotes
[1] All growth rates are calculated logarithmically.

Source: Statistics Canada. Table 327-0011 - Electric utility construction price indexes (EUCPI), annual (index, 1992=100)

Notes:
Table 327-0011 release schedule is as follows for a year *t* :
In September/October of *t*, preliminary first-half data are released for *t* ;
in April of *t* + 1, preliminary annual data are released for *t;*
in September/October of *t* + 1, revised annual data are released for *t;*
and in April of *t* + 2, final annual data are released for *t.*

Table 10

Canadian Natural Gas Distribution, Water, and Other Systems Capital Stock Price Indexes

	Information and communication technologies machinery and equipment[1]		Non-information and communication technologies machinery and equipment[2]		Building structures		Engineering structures		Land	
Year	Level	Growth Rate[3]	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate
1961	3091.7		17.5		17.9		12.6		35.4	
1962	3102.6	0.4%	17.9	2.3%	17.8	-0.6%	12.7	0.8%	32.8	-7.6%
1963	3165.2	2.0%	20.1	11.6%	18.2	2.2%	13.1	3.1%	30.4	-7.6%
1964	3205.4	1.3%	18.7	-7.2%	18.4	1.1%	13.6	3.7%	28.6	-6.1%
1965	3282.6	2.4%	19.3	3.2%	19.2	4.3%	14.4	5.7%	28	-2.1%
1966	3226.8	-1.7%	19.7	2.1%	20.5	6.6%	15.2	5.4%	27.9	-0.4%
1967	3312.1	2.6%	19.5	-1.0%	21.3	3.8%	16	5.1%	27	-3.3%
1968	3325.9	0.4%	19.4	-0.5%	21.2	-0.5%	16.2	1.2%	25.8	-4.5%
1969	3353.1	0.8%	19.8	2.0%	22.2	4.6%	17.1	5.4%	25.7	-0.4%
1970	3408.4	1.6%	20.9	5.4%	23.3	4.8%	18.1	5.7%	25.6	-0.4%
1971	3505.1	2.8%	21.5	2.8%	24.6	5.4%	19.3	6.4%	26.1	1.9%
1972	3522.7	0.5%	22	2.3%	26.9	8.9%	20.5	6.0%	27.6	5.6%
1973	3564.8	1.2%	23	4.4%	29	7.5%	21.8	6.1%	31	11.6%
1974	3466.6	-2.8%	26.2	13.0%	35.4	19.9%	26.1	18.0%	36.1	15.2%
1975	3606.7	4.0%	31	16.8%	40.4	13.2%	30.8	16.6%	39.7	9.5%
1976	3213.5	-11.5%	32.8	5.6%	41.3	2.2%	33.4	8.1%	40.9	3.0%
1977	2807.1	-13.5%	36.2	9.9%	42.2	2.2%	36	7.5%	43.4	5.9%
1978	2060.2	-30.9%	40.5	11.2%	43.8	3.7%	38.8	7.5%	45.2	4.1%
1979	1826.7	-12.0%	45.2	11.0%	46.9	6.8%	42.7	9.6%	49.9	9.9%
1980	1347.4	-30.4%	50.4	10.9%	52.1	10.5%	47.1	9.8%	56.7	12.8%
1981	1139	-16.8%	56.2	10.9%	60.4	14.8%	52.2	10.3%	62.8	10.2%
1982	1108.6	-2.7%	60.7	7.7%	65.3	7.8%	57.9	10.4%	65.2	3.8%
1983	793.6	-33.4%	61.8	1.8%	64	-2.0%	60.8	4.9%	63.6	-2.5%
1984	688.1	-14.3%	64.7	4.6%	62.7	-2.1%	62.8	3.2%	64	0.6%
1985	576.5	-17.7%	68.5	5.7%	63.9	1.9%	64.6	2.8%	64	0.0%
1986	486.4	-17.0%	70.6	3.0%	66.5	4.0%	66.5	2.9%	66.2	3.4%
1987	409.9	-17.1%	70.6	0.0%	70.8	6.3%	68.2	2.5%	69.3	4.6%
1988	373.8	-9.2%	70.1	-0.7%	75.2	6.0%	71.9	5.3%	74	6.6%
1989	316.2	-16.7%	72.2	3.0%	80.4	6.7%	74.6	3.7%	78.2	5.5%
1990	286.2	-10.0%	74	2.5%	83.2	3.4%	77.5	3.8%	81	3.5%
1991	230.6	-21.6%	72	-2.7%	80.4	-3.4%	79.6	2.7%	80.3	-0.9%
1992	204.5	-12.0%	74.8	3.8%	80.4	0.0%	81	1.7%	79.8	-0.6%
1993	197.5	-3.5%	77.8	3.9%	80.6	0.2%	82.5	1.8%	81.8	2.5%
1994	185.6	-6.2%	81.5	4.6%	82.2	2.0%	85.6	3.7%	84.5	3.2%
1995	169	-9.4%	84.7	3.9%	84.7	3.0%	86.1	0.6%	87.1	3.0%
1996	146.3	-14.4%	86.3	1.9%	86	1.5%	89.2	3.5%	89.8	3.1%
1997	135.1	-8.0%	87.5	1.4%	87.7	2.0%	91.7	2.8%	91.3	1.7%
1998	122.6	-9.7%	93.3	6.4%	89.3	1.8%	94.6	3.1%	92.7	1.5%
1999	109.7	-11.1%	94.8	1.6%	91	1.9%	96.4	1.9%	94.7	2.1%
2000	105.2	-4.2%	95.7	0.9%	95.6	4.9%	98.7	2.4%	97.2	2.6%
2001	103.6	-1.5%	98.3	2.7%	98.5	3.0%	98.8	0.1%	98.1	0.9%
2002	100	-3.5%	100	1.7%	100	1.5%	100	1.2%	100	1.9%
2003	92.5	-7.8%	93.3	-6.9%	102.6	2.6%	101.1	1.1%	103.9	3.8%
2004	85.8	-7.5%	89.6	-4.0%	108.7	5.8%	107.2	5.9%	112.9	8.3%
2005	79.5	-7.6%	87.6	-2.3%	114	4.8%	113.9	6.1%	123.2	8.7%
2006	76.3	-4.1%	85.6	-2.3%	122.8	7.4%	122.1	7.0%	137	10.6%
2007	74.7	-2.1%	84.5	-1.3%	136	10.2%	128.4	5.0%	151.2	9.9%
2008	75.1	0.5%	86.1	1.9%	150.3	10.0%	134	4.3%	161.6	6.7%
Average Annual Growth Rates										
1962-2008		**-7.9%**		**3.4%**		**4.5%**		**5.0%**		**3.2%**
1969-2008		**-9.5%**		**3.7%**		**4.9%**		**5.3%**		**4.6%**
1979-2008		**-11.0%**		**2.5%**		**4.1%**		**4.1%**		**4.2%**
1989-2008		**-8.0%**		**1.0%**		**3.5%**		**3.1%**		**3.9%**
1999-2008		**-4.9%**		**-0.8%**		**5.2%**		**3.5%**		**5.6%**

Footnotes
[1] Information and communication technologies machinery and equipment consists of computer hardware, software and telecommunication equipment
[2] Machinery Equipment other than computer hardware, software and telecommunication equipment.
[3]All growth rates are calculated logarithmically.

Sources:
Statistics Canada. Table 383-0025 - Investment, capital stock and capital services of physical assets, by North American Industry Classification System (NAICS), annual (dollars unless otherwise noted) (index, 2002=100)

Notes
• Table 383-0025 data become available between November and beginning of January for the year three years or four years prior, respectively (e.g. Data for 2008 became available in Nov, 2011)

Table 11

Canadian Non-Residental Building Construction Price Indexes

	Seven Census Metropolitan Area Composite						Vancouver, British Columbia					
	Total, non-residential building construction		Total, commercial structures		Total, industrial structures		Total, non-residential building construction		Total, commercial structures		Total, industrial structures	
Year	Level	Growth Rate[1]	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate
1981	58.3		59.8		52.5		65.1		66.6		63.3	
1982	62.8	7.4%	64.4	7.4%	56.4	7.2%	70.6	8.1%	72.0	7.8%	68.6	8.0%
1983	62.0	-1.3%	63.2	-1.9%	56.4	0.0%	70.6	0.0%	71.6	-0.6%	69.4	1.2%
1984	60.8	-2.0%	61.8	-2.2%	56.3	-0.2%	67.6	-4.3%	67.9	-5.3%	66.7	-4.0%
1985	62.2	2.3%	63.1	2.1%	58.6	4.0%	68.0	0.6%	68.2	0.4%	67.0	0.4%
1986	65.0	4.4%	66.0	4.5%	62.0	5.6%	70.1	3.0%	70.3	3.0%	68.9	2.8%
1987	69.7	7.0%	71.0	7.3%	65.8	5.9%	71.5	2.0%	71.6	1.8%	70.8	2.7%
1988	74.6	6.8%	76.1	6.9%	70.6	7.0%	75.8	5.8%	75.8	5.7%	75.3	6.2%
1989	79.5	6.4%	81.1	6.4%	75.8	7.1%	82.1	8.0%	82.4	8.3%	81.5	7.9%
1990	81.8	2.9%	83.3	2.7%	78.0	2.9%	85.0	3.5%	85.0	3.1%	84.2	3.3%
1991	78.8	-3.7%	79.8	-4.3%	76.0	-2.6%	81.2	-4.6%	81.2	-4.6%	79.9	-5.2%
1992	78.7	-0.1%	79.6	-0.3%	76.0	0.0%	82.6	1.7%	82.6	1.7%	81.2	1.6%
1993	79.2	0.6%	80.0	0.5%	76.7	0.9%	84.7	2.5%	84.7	2.5%	83.4	2.7%
1994	80.8	2.0%	81.5	1.9%	78.8	2.7%	86.5	2.1%	86.6	2.2%	85.7	2.7%
1995	83.4	3.2%	84.0	3.0%	81.2	3.0%	89.4	3.3%	89.4	3.2%	88.4	3.1%
1996	84.8	1.7%	85.3	1.5%	82.8	2.0%	91.1	1.9%	91.0	1.8%	90.4	2.2%
1997	86.7	2.2%	87.0	2.0%	85.0	2.6%	93.0	2.1%	92.9	2.1%	92.5	2.3%
1998	88.5	2.1%	88.8	2.0%	86.8	2.1%	94.8	1.9%	94.9	2.1%	94.1	1.7%
1999	90.1	1.8%	90.4	1.8%	88.6	2.1%	95.7	0.9%	95.8	0.9%	94.9	0.8%
2000	95.1	5.4%	95.3	5.3%	94.3	6.2%	97.6	2.0%	97.8	2.1%	97.2	2.4%
2001	98.2	3.2%	98.3	3.1%	97.8	3.6%	99.0	1.4%	99.1	1.3%	98.9	1.7%
2002	100.0	1.8%	100.0	1.7%	100.0	2.2%	100.0	1.0%	100.0	0.9%	100.0	1.1%
2003	103.0	3.0%	102.9	2.9%	103.1	3.1%	101.3	1.3%	101.1	1.1%	101.5	1.5%
2004	109.7	6.3%	109.4	6.1%	111.0	7.4%	110.0	8.2%	109.6	8.1%	112.0	9.8%
2005	115.9	5.5%	115.5	5.4%	118.0	6.1%	118.0	7.0%	117.4	6.9%	121.1	7.8%
2006	124.9	7.5%	124.6	7.6%	127.3	7.6%	130.2	9.8%	129.4	9.7%	133.5	9.7%
2007	136.8	9.1%	137.2	9.6%	138.4	8.4%	146.7	11.9%	146.1	12.1%	150.2	11.8%
2008	150.8	9.7%	151.3	9.8%	154.2	10.8%	159.6	8.4%	158.8	8.3%	167.2	10.7%
2009	142.0	-6.0%	141.4	-6.8%	146.7	-5.0%	136.0	-16.0%	134.8	-16.4%	136.9	-20.0%
2010	141.4	-0.4%	140.6	-0.6%	146.2	-0.3%	132.8	-2.4%	131.4	-2.6%	131.8	-3.8%
2011	146.6	3.6%	145.6	3.5%	152.2	4.0%	137.9	3.8%	136.4	3.7%	138.9	5.2%
2012	150.7	2.8%	149.6	2.7%	156.6	2.8%	142.6	3.4%	141.1	3.4%	145.2	4.4%
Average Annual Growth Rates												
1989-2008		**3.5%**		**3.4%**		**3.9%**		**3.7%**		**3.7%**		**4.0%**
1999-2008		**5.3%**		**5.3%**		**5.7%**		**5.2%**		**5.1%**		**5.7%**
1983-2012		**2.9%**		**2.8%**		**3.4%**		**2.3%**		**2.2%**		**2.5%**
1993-2012		**3.2%**		**3.2%**		**3.6%**		**2.7%**		**2.7%**		**2.9%**
2003-2012		**4.1%**		**4.0%**		**4.5%**		**3.5%**		**3.4%**		**3.7%**

Footnotes

[1] All growth rates are calculated logarithmically.

Source:
Statistics Canada. Table 327-0043 - Price indexes of non-residential building construction, by class of structure, quarterly (index, 2002=100)

Notes
• Data are released on a quarterly basis. Data for each quarter are released during the second or third week of the month two months following the end of the quarter (e.g. Q3 2013 data were released 11/12/2013).

Of these, we believe that EUCPIs are the most accurate measures of trends in the construction costs of Canadian power distribution and transmission systems. The CSPI for natural gas distribution, water, and other systems engineering structures is the single most accurate measure of construction cost trends of Canadian gas distributors. Unfortunately, it is not available in a timely fashion, and has not to our knowledge been updated since 2008. None of these utility construction cost indexes are available for BC specifically.

Non-residential building construction price indexes are available for Vancouver and a seven Canadian metropolitan area composite. The difference between growth rates for Vancouver and the nation could be used to make national utility construction cost indexes more relevant in a BC application. Inspecting the results in Table 11, it can be seen that in recent decades the non-residential construction prices in Vancouver have tended to lag those in Canada as a whole by about 50 basis points annually.

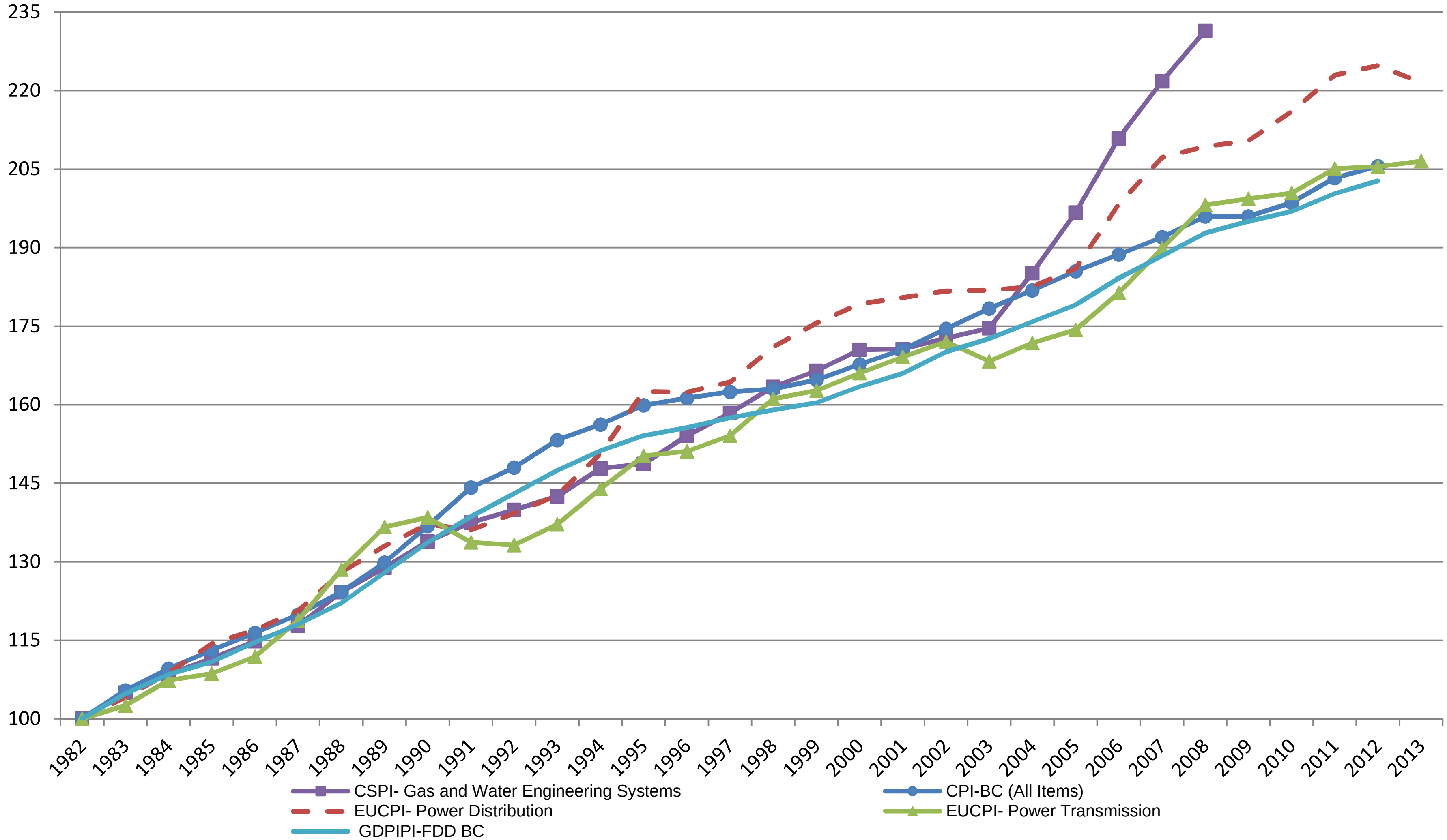
Figure 5 displays the trends in the transmission and distribution EUCPIs, the CSPI for gas and water engineering structures, and two macroeconomic price indexes for BC. It can be seen that the summary EUCPI for power distribution did a fairly good job of tracking the trend in the CSPI for engineering structures. Both have been fairly volatile. On the basis of this comparison, we recommend the EUCPI for power distribution as the best available measure of the trend in gas utility construction prices. The EUCPI for power transmission has displayed a less volatile trajectory that is reasonably well tracked by the two macroeconomic indexes.

5.3 Inflation Measure Recommendations

Before making inflation measure recommendations, it is important to recognize that several ARM design options are available to the Commission. Fortis proposes cost escalation indexes for O&M expenses and two kinds of capex. A significant portion of all capex cost would be recovered by other means. One alternative to the Fortis proposal is escalation indexes for capital *cost* (depreciation and return on rate base) rather than capital *expenditures*. Another alternative is comprehensive revenue cap indexes like those recently approved for gas distributors in Alberta.

Figure 5

Comparing Alternative Canadian Construction Cost Indexes



Should the Commission wish to use a macroeconomic output price index in the inflation measures for the Fortis companies, we recommend on the basis of this review either the CPI^{BC} or the $GDPIPI^{FDD}$ for BC. Both indexes reflect BC inflation conditions. The $GDPIPI^{FDD}$ for BC is less sensitive to irrelevant commodity price fluctuations, but forecasts of this index are to our knowledge unavailable. The low likelihood of hyperinflation in the next few years reduces the need to forecast inflation a macroeconomic inflation measure subject to a trueup. However, forecasts have the benefit of reducing operating risk without weakening performance incentives.

The lack of substantial MFP growth in the Canadian economy eliminates one of the biggest traditional arguments favoring industry-specific inflation measures. We believe that the recommended macroeconomic inflation measures can be considered for use in a comprehensive revenue (or cost) cap index as well as in O&M and capital cost indexes. We have shown, however, that inflation in power and gas utility construction costs can deviate substantially from macroeconomic inflation. Figure 5 shows, for example, that there has been a substantial slowdown in electric utility construction cost inflation since 2011. The EUCPI for power distribution grew only 0.8% in 2012 and has fallen by 1.4% in 2013. The EUCPI for power transmission grew by 0.2% in 2012 and 0.5% in 2013. In the next few years, there is a material risk of overcompensation were the kind of inflation measure proposed by Fortis to be applied to capex budgets.

We accordingly believe that industry-specific indexes would be warranted should the Commission approve escalation indexes for capex budgets. The summary EUCPIs are more accurate for this purpose than the index that Fortis has proposed. A 50/50 weighting of the transmission and distribution EUCPI growth rates would be sensible for FBC. EUCPI growth can be smoothed if desired to reduce volatility. It would, be reasonable to reduce the EUCPI growth rates of these national indexes by 50 basis points each year to better reflect BC inflation conditions.

Were a macroeconomic price index to be used as the sole inflation measure in any of the ARMs, the question arises as to whether X should be adjusted to reflect the productivity trend of the Canadian economy. The trend in the MFP index for the Canadian private business sector was close to zero over the last twenty years but modestly negative in the last ten years. US utilities routinely ask for, and have on several occasions received, X factor reductions when the MFP trend of the economy is positive. It is unclear what sectors of the Canadian economy contribute to the MFP decline. It is possible that the negativity is chiefly due to resource extraction industries that export a sizable percentage of their output. Absent convincing evidence to the contrary, however, there is an argument for a modest positive X factor adjustment.

Suppose now that the Commission prefers industry-specific inflation measures for O&M expenses or total cost. We recommend in this event use of either the BC AHE or AWE for the labor price index. The availability of forecasts is one criterion for choosing between these options. Care must be taken to ensure that the labor price weight equals the share of direct labor expenses (*i.e.* salary, wage, pension, and benefit expenses) in the applicable cost. A 55% labor price weight is certainly too high in an application to capital cost or total cost. Under regulatory accounting capital cost is, as we discuss in Section 2.3.1, a function of construction prices over many years and not only of the construction price in the current year. Thus, insofar as labor prices affect the cost of capital, it is the trend in the prices over many years that is relevant and not the current price.

Another cause for concern with a high labor price weight is that a macroeconomic inflation measure like the CPI^{BC} would apply to a collection of costs that comprises materials, services, and non-labor capex. The underlying technology for the provision of consumer products may well be more labor intensive than the underlying technology for the provision of the inputs in this residual input basket. The Statistics Canada MFP index for the aggregate economy, for instance, has a cost share weight for labor that is several times the weight for capital. Given the tendency of labor prices to growt more rapidly than prices of other inputs, and the slight decline in the MFP growth for the private business sector, we are concerned that CPI^{BC} will tend to overestimate the input price inflation of the residual cost group to which it would be applied.

6. Appraising the B&V Studies

This section contains an appraisal of the productivity studies provided by B&V. We begin with a general discussion of the Kahn method. There follows a critique of the method that B&V employed.

6.1 The Kahn Method

The Kahn method is an alternative means of designing ARMs using utility industry statistics. Dr. Alfred Kahn, a Cornell University regulatory economist, detailed the method in 1993 testimony for a group of shippers in a FERC proceeding on PBR for interstate oil pipelines.[12] The FERC still uses this method to set X factors for oil pipelines.

The rationale for Kahn's method has roots in the index logic for ARM design we detailed in Section 2.2. We consider here its application in the design of a revenue cap index. The analysis applies with equal force to a cost target. Suppose that a utility will be subject to an RCI of general form

$$\textit{Growth Revenue} = \textit{Inflation} - X + \textit{growth Outputs}^{C}$$

where *Inflation* is the growth in the RCI inflation measure. Having chosen an inflation measure, we might then choose a companion value for X such that the average growth rate in hypothetical RCIs for a group of utilities equals the average growth in the cost of the utilities. Denoting average annual growth rates ("trends") in boldface, we seek the value of X such that

$$\boldsymbol{Inflation} - X + \boldsymbol{trend\ Outputs^{C}} = \boldsymbol{trend\ Cost}. \qquad [18]$$

Solving for X, we obtain

$$\begin{aligned} X &= \boldsymbol{Inflation} - (\boldsymbol{trend\ Cost} - \boldsymbol{trend\ Outputs^{C}}) \\ &= \boldsymbol{Inflation} - (\boldsymbol{trend\ Cost/Outputs^{C}}) \qquad [19] \end{aligned}$$

X is the amount by which the inflation trend exceeds the unit cost trend of the sampled utilities. In the words of Dr. Kahn, "The ideal indexation formula would be one

[12] "Testimony of Alfred E. Kahn on Behalf of a Group of Independent Refiner/Shippers" in Docket No. RM93-11-000 (Revision to Oil Pipeline Regulations Pursuant to the Energy Policy Act of 1992), August 12, 1993.

that…tracked as closely as possible the actual average costs of the pipeline industry.” [13]

In 1993, Kahn undertook such a calculation using data for the 1982-92 period for a sample of oil product pipelines. This was the longest sample period that available data permitted at the time that he filed the study. Using a producer price index for finished goods as the inflation measure he found that an X factor of 0.90% was indicated.

Recollecting relation[1], we can restate [19] as

$$X = \textbf{\textit{Inflation}} - [(\textbf{\textit{trend Input Prices}} + \textbf{\textit{trend Inputs}}) - \textbf{\textit{trend Outputs}}^{\boldsymbol{C}})]$$
$$= \textbf{\textit{trend MFP}}^{\boldsymbol{C}} + (\textbf{\textit{Inflation}} - \textbf{\textit{trend Input Prices}}). \qquad [20]$$

The estimated X is thus the estimated sum of the trends in MFP^C and the inflation differential as discussed in Section 2.2.4 above.

Suppose, now, that the RCI inflation measure is the comprehensive GDPPI. Then

$$X = \textbf{\textit{trend MFP}}^{\boldsymbol{C}} + (\textbf{\textit{trend GDPPI}} - \textbf{\textit{trend Input Prices}})$$
$$= \textbf{\textit{trend MFP}}^{\boldsymbol{C}}_{\textbf{\textit{Industry}}} +$$
$$[(\textbf{\textit{trend Input Prices}}_{\textbf{\textit{Economy}}} - \textbf{\textit{trend MFP}}_{\textbf{\textit{Economy}}}) - \textbf{\textit{trend Input Prices}}_{\textbf{\textit{Industry}}}]$$
$$= (\textbf{\textit{trend MFP}}^{\boldsymbol{C}}_{\textbf{\textit{Industry}}} - \textbf{\textit{trend MFP}}_{\textbf{\textit{Economy}}}) +$$
$$(\textbf{\textit{trend Input Prices}}_{\textbf{\textit{Economy}}} - \textbf{\textit{trend Input Prices}}_{\textbf{\textit{Industry}}}). \qquad [21]$$

The estimated X can in this case also be described as an estimate of the sum of a productivity differential and an input price differential.

This discussion reveals that the Kahn method can produce results that are pertinent in X factor calibration without calculating industry input price and MFP indexes. This “indirect” method can produce substantial regulatory cost savings. An ability to avoid calculating capital price and quantity indexes is especially valuable since these calculations are complicated. Accurate calculations using Kahn’s method nonetheless do involve challenges. For example, an appropriate output quantity index must be developed, and the trend in total cost must be calculated.

With respect to the latter task, consider that the pro forma cost of base rate inputs (which includes a full return on rate base) is the sum of non-fuel operating expenses (non-fuel O&M expenses, depreciation, amortization, and taxes) and the pro forma return

[13] *Ibid* p. 2

on rate base.[14] Dr. Kahn chose not to calculate the sum of income taxes and return on rate base directly. He asserted that the trend in net plant value was a reasonable proxy for the trend in these costs. While acknowledging that the trend in these costs also depends on the trend in the ROR, he argued that this trend should be ignored because the remarkable decline in the ROR that occurred during the 1982-92 sample period was unlikely to be repeated.

It may be noted that it would be improper to measure the trend in total cost as the trend in the sum of net plant value and operating expenses. The net plant value in a given year is depreciated over decades and greatly exceeds the *annual* income taxes and return on capital it gives rise to, and also greatly exceeds annual O&M expenses. To sidestep this additivity problem, Dr. Kahn took advantage of the following basic result from calculus:

$$growth\ Cost = SUM_j\ sc_j \times growth\ Cost_j. \qquad [22]$$

where sc_j is the share of input group j in the applicable total cost. Relation [22] states that the growth in cost is a cost-share-weighted average of the growth in individual cost components.[15] Kahn then estimated the growth in the total cost of sampled pipelines using a cost trend index with formula

$$growth\ Cost = sc_{RT} \times growth\ Net\ Plant\ Value + sc_O \times growth\ Operating\ Expenses.$$[16]

This calculation requires cost shares for taxes and the return on capital ("sc_{RT}") and other operating expenses ("sc_O"). Data on operating expenses were readily available from pipeline reports to regulators. Kahn estimated income taxes and the annual return on rate base residually as the difference between operating revenue and operating expenses. This is sometimes called an "ex post" approach to capital cost measurement.

Our discussion of the Kahn method has implications for the development of X factors for Fortis.

[14] By a "pro forma" return on rate base we mean the product of the rate base and the authorized rate of return.

[15] Suppose, for example, that there are two cost categories such that $C = C_1 + C_2$. Then $dlnC/dT = (1/C)x(dC_1/dT + dC_2/dT) = (C_1/C)x(1/C_1)x(dC_1/dT) + (C_2/C)x(1/C_2)x(dC_2/dT) = (C_1/C)x(dlnC_1/dT) + (C_2/C)x(dlnC_2/dT)$.

[16] As Kahn states on p. 4 of his Appendix on Data and Methodology, "the samples were used primarily to analyze rates of change in three measures of pipeline costs: operating expenses per barrel-mile, net investment per barrel-mile, and a weighted average of the two. The basis for the relative weighting of the first two in calculating the third was the ratio of operating expenses to operating revenues…."

- The Kahn method is designed to calibrate the X factor given a specific inflation measure and not to estimate the MFP trend. The reason input price and productivity indexes aren't needed is that the methodology does not itemize input price and productivity trends.
- When the Kahn estimate of X is used to estimate the MFP^C trend, relation [21] shows that if GDPPI is used as the inflation differential, the Kahn estimate is biased by the MFP trend of the economy less the input price differential. A Kahn method using US data might nonetheless be used to calibrate the X factor of a Canadian PBR plan were the input price differentials and the MFP trends similar in the United States and Canada. However, there is no reason to believe that they are. In particular, we have noted that the MFP trends of the two economies have been quite different. Since the MFP trend of the US economy is much larger, an X factor calculated using US data would tend to be too low.
- An application of Kahn's method to US utility data therefore cannot be used to calculate MFP^C without modification. A more precise method would require the calculation of a utility input price index. This would erode the cost savings from the Kahn method substantially.
- Whether or not the output index is cost based and excludes volatile usage variables, the sample period matters when using Kahn's method because an inflation differential is implicit in the calculation and this can be volatile. It is notable that in 1993 Dr. Kahn used the longest sample period that available data permitted at the time.
- The Kahn method is intended to approximate the approach to capital cost measurement that is used in cost of service regulation. Recollect that this approach typically involves straight line depreciation and book valuation of plant.
- Many of the issues that arise in the calibration of X using input price and productivity research also arise when the Kahn method is employed. These include the design of the output index and the choice of a utility peer group.

6.2 The B&V Studies

6.2.1 Description

B&V present the results of studies that purport to calculate the trends in the productivity of US gas utilities and of the transmission and distribution ("T&D") operations of US electric utilities. The studies are intended to inform the selection of X factors for the Fortis PBR plans. Although separate reports were prepared for the gas and electric studies, much of the language in the two reports is the same.

The B&V productivity studies have the following notable features.

- The studies addressed the multifactor productivity (which the authors call "TFP") of utilities but not their O&M or capital productivity. This limits the relevance of their research in setting X factors for detailed cost categories. B&V also did not consider the implications for X factors of addressing a large portion of capex cost outside of the indexing mechanism.
- Cost-based output indexes were employed in the unit cost calculations. Multiple output specifications were considered. In the gas report, the output specifications considered are the total number of customers served, a measure of delivery capacity, and a summary output index with two output variables: the same delivery capacity variable and a density-adjusted customer variable. The output specifications considered in the electric study are the total number of customers, a measure of substation capacity, and summary output indexes featuring two output variables: the same delivery capacity variable and a density-adjusted customer variable.
- The trend in the input quantity is measured by the "change in weighted cost of capital and total expenses" (gas and electric reports p. 9). The cost trend is measured using a two-category cost index that itemizes capital and O&M costs. The construction of this index requires cost shares for the two cost categories.
- The authors state (gas and electric reports p. 10) that "the calculation of this cost is based on a method that the Federal Energy Regulatory Commission (FERC) refers to as the *Kahn Method.*" This statement is true in three

respects. First, the cost trend is measured using a cost index rather than the trend in the total annual pro forma cost of service. Secondly, the capital cost used to calculate the capital cost share weight is calculated residually as the difference between operating revenues and certain expenses. Thirdly, net plant value is used to estimate the trend in some capital costs. The authors note (gas and electric reports p. 10) that "this method benefits from not having to develop a composite measure or to estimate the quantity of each input used from data that does not permit direct measurement of the quantity of the factor used)".

- The authors included expenses for uncollectible bills, pensions and other benefits, and customer service and information in both studies.
- Both studies rely chiefly on data reported to government agencies by utilities. These data have been gathered and processed by reputable commercial venders. The chief sources of the gas and electric data are SNL Financial and Ventyx Velocity Suite, respectively.
- The number of companies from which data have been drawn are sizable. There are 95 companies in the gas sample and 72 in the electric sample.
- The sample periods of both studies are 2008-2011.
- The authors report average annual TFP growth rates for sampled utilities that are extraordinarily negative: -4.07% for gas and – 4.87% for electric.

6.2.2 Critique

Methodological Issues

The B&V study has numerous flaws that reduce its relevance in this proceeding to the vanishing point. The biggest single flaw is that the trend in the cost of a utility is a materially biased measure of the trend in its input quantities. In using the cost trend, B&V therefore materially bias their productivity trend estimate. Recalling relation [1],

$$\textit{growth Outputs}^{C} - \textit{growth Cost}$$
$$= (\textit{growth Outputs}^{C} - \textit{growth Inputs}) - \textit{growth Input Prices.}$$

Thus, the B&V estimates of the MFP trends are downward biased by the trends in utility input price inflation. We reported in Sections 3 and 4 that the input price inflation of energy distributors averaged more than 300 basis points annually in the United States during these years. This is thus a very large error, and by itself goes a long ways towards explaining the unusually negative trends produced by B&V. The fact that Dr. Kahn used a cost index somewhere in his calculations is not an adequate defense. We have shown that Dr. Kahn was not measuring MFP.

Another major flaw in the B&V methodology is the choice of the sample period. A sample period involving only four growth rates for each company is extraordinarily short for measurement of a long-run productivity trend. To make matters worse, the four years chosen include the worst recession the United States has experienced in seventy years. The rebound in the following two years did not come close to restoring economic activity to its previous level.

The authors state (gas report p. 10) that "because measures of output do not suffer from volatility caused by weather or by the business cycle directly, there is much less need for using long historical periods to estimate TFP for use with a much shorter control period." While this is true, the recession that occurred centered on the housing market. As a consequence, customer growth during this period was well below historical norms, as we reported in Sections 3 and 4. Furthermore, a recession causes certain utility costs to rise much more rapidly than their secular trends. For example, pension contributions can surge to offset the drop in equity prices.

With the Kahn method for X factor calibration, another problem with a short sample period is the volatility of the implicit inflation differential. The recession slowed inflation in prices of finished goods and services much more than inflation in utility input prices. This would tend to lower the X that is indicated by the method temporarily.

A third and related problem with the B&V study is that they included some costs that rose unusually rapidly during the sample period. These included costs of uncollectible bills and pension and benefit expenses. Customer service and information expenses also grew quite rapidly during the period, especially for electric utilities, due to rapid growth in demand-side management ("DSM") programs. DSM expenses are not itemized for easy removal in the US data forms. Recollecting our discussion in Section 2.2.7, DSM costs should be excluded in any event because they are not covered by the proposed ARMs.

A fourth major problem is the improper measurement of trends. We have shown that the growth of a proper cost trend index is a cost-share weighted average of the *growth* in the component costs. This finesses the problem of cost subindexes with different numeraires that make them impossible to meaningfully add up. B&V instead compute cost *level* indexes and then calculate the growth rates in these indexes. The trend in net plant value improperly dominates these calculations since, as we have discussed, net plant value is not a measure of annual cost like the O&M expenses that B&V uses.

A similar problem is encountered with the calculation of output trends. Instead of a proper output trend index, B&V calculated an output *level* index and then calculated its growth rate. In this case, the trend in the capacity index improperly dominated the trend in the number of customers served because of a different numeraire. One indication of the problem is that the estimated electric productivity trend would likely depend on whether substation capacity was measured in kVA or MVa.

In the electric study, another major concern is that the growth in power *transmission* costs grew much more rapidly than the growth in *distributor* costs during the sample period. For example, transmission O&M expenses averaged 4.51% annual growth whereas distribution expenses averaged 2.35% growth and customer account expenses averaged only 0.23% growth. The rapid growth in transmission O&M expenses may be due in part to the fact that B&V improperly included expenses for transmission *by others*. This is essentially a cost of power supply and may have grown rapidly during the sample period for some utilities as they purchased more power from generation facilities that are not on their system. Higher growth in transmission O&M expenses may also reflect rising charges by independent transmission system operators.

Consider also that average annual growth in transmission net plant value was 8.19% whereas that for net distribution plant value was 4.49% and that for net general plant value was 4.71%. Rapid growth in transmission plant may reflect the exigencies of bulk power market restructuring in some states which will have no counterpart at FBC during the proposed term of the PBR plan.

The B&V study also makes some smaller methodological errors.

- B&V deviate from the Kahn method in making the trend in net plant value a proxy for the trend in *depreciation and amortization expenses* as well as the trend in income taxes and the return on rate base. This is unnecessary and inadvisable inasmuch as data on depreciation and amortization expenses are available.
- In calculating the capital cost share for power T&D, B&V took the difference between electric operating revenue and power production O&M expenses. This is not a valid approximation of *T&D* capital cost because the residual includes revenue that compensates vertically integrated electric utilities ("VIEUs") for the (relatively large) return on power production plant.
- In the gas study, B&V perhaps intended to have a cost index that averaged the trends in capital cost and O&M expenses. In implementation, however, they matched the (non-gas) O&M cost share (column J) with (non-gas) *operating revenues* (column G) rather than non0gas O&M expenses (column I).
- On Dec. 13 2013 the authors filed an errata version of their gas report in which they reported a mathematical error in the formula for the summary output index. The revised formula is

  $$Output = wt_1 \, x \; Customers \; x \; Density \; Index + wt_2 \, x \; Capacity.$$

  whereas the prior formula was

  $$Output = wt_1 \, x \; Customers \, / \, Density \; Index + wt_2 \, x \; Capacity$$

  It is unclear to us which approach to customer density has more intuitive appeal, since it makes some sense for the incremental cost of customer growth to be greater when customer density is *low* rather than *high*.
- B&V calculates the average annual growth rates in the cost and output indexes by averaging their *arithmetic* growth rates. This is well known to be an inaccurate method. It is more accurate to take the average of <u>logarithmic</u> growth rates.

In addition to these flaws, mention should be made of some additional limitations of the Kahn method even if correctly applied. For example, the residual method for calculating weights for the cost trend index is inexact. For example, residual operating revenue is sensitive to volume fluctuations, and to that extent does not reflect the pro forma return on capital. The influence of volume fluctuations on operating revenue can be material, given the heavy weight typically applied to delivery volumes and peak demand in energy distributor rate designs.

Considering all the disadvantages of the Kahn method in the design of an X factor for Canadian utilities using US data, it is not clear why it would be preferable to input price and productivity indexing. High quality data on US gas and electric utility operations can be gathered and processed at reasonable cost for use in input price and productivity research. The cost of such studies has fallen as increasing demand has made it possible to spread fixed costs of the research over more customers.

B&V Study Corrections

To illustrate the problems with B&V's research methodology, we have made corrections to their results for some of the flaws. Results of our gas and electric calculations appear in Tables 12 and 13, respectively.[17] [18] We do not believe that the corrected results are of sufficient quality to serve as the basis for X factor calibration. For example, we are still concerned that the sample period is too short and that costs are included in the study that should be excluded.

Considering first B&V's gas study, we began the correction sequence by employing logarithmic rather than arithmetic growth rates. Using B&V's composite output measure, this raises the average annual growth in the MFP estimate substantially, from **-4.96%** to **-4.08%**. We next employ proper output and cost trend indexes using B&V's subindexes. This further raises the average annual growth in the MFP estimate to **-3.43%.** We next use O&M expenses as a cost subindex instead of operating revenues. This has little effect on the average annual growth in the MFP estimate, changing it to **-3.45%**. Using SNL data, we next add each utility's depreciation expenses to non-gas O&M expenses and use this as one of the two cost trend subindexes. This required an adjustment to the cost index weights. Some depreciation values were imputed in this exercise due to lack of data. The trend in net plant value now applies only to the trend in the return on plant. This correction raises the MFP trend estimate slightly, to **-3.40%.**

[17] The results that we report for B&V differ from those that B&V report due to errors in their computations of average annual growth rates.
[18] In preparing our initial filing we were unaware that Fortis had filed errata on its electric study as well as its gas studies. In this errata draft we provide updated electric results in Table 13.

Table 12

Alternative Kahn Method Calculations For U.S. Gas Distributors

(Average Annual Growth Rates 2008-2011)

			Output Specification			
			"Output Measure"	**Customers Only**	**Capacity Only**	**Line Miles Only**
Black & Veatch	**Output**	[A]	0.82%	0.88%	0.51%	N/A
	Cost Index	[B]	5.79%	5.79%	5.79%	N/A
	"Productivity" Estimate	[C = A - B]	**-4.96%**	**-4.91%**	**-5.28%**	N/A
Correction 1: Logarithmic Growth Rates	**Output**	[D]	0.68%	0.79%	0.28%	0.91%
	Cost Index	[E]	4.75%	4.75%	4.75%	4.75%
	"Productivity" Estimate	[F = D - E]	**-4.08%**	**-3.97%**	**-4.48%**	**-3.84%**
	Change in Estimate		*0.89%*	*0.94%*	*0.80%*	*N/A*
Correction 2: Output and Cost Trend Indexes	**Output**	[G]	0.53%	0.79%	0.28%	0.91%
	Cost Index	[H]	3.96%	3.96%	3.96%	3.96%
	"Productivity" Estimate	[I = G - H]	**-3.43%**	**-3.17%**	**-3.68%**	**-3.05%**
	Change in Estimate		*0.65%*	*0.79%*	*0.79%*	*0.79%*
Correction 3: O&M Expenses is Cost Subindex	**Output**	[J]	0.53%	0.79%	0.28%	0.91%
	Cost Index	[K]	3.98%	3.98%	3.98%	3.98%
	"Productivity" Estimate	[L = J - K]	**-3.45%**	**-3.19%**	**-3.70%**	**-3.07%**
	Change in Estimate		*-0.02%*	*-0.02%*	*-0.02%*	*-0.02%*
Correction 4: Add Depreciation to O&M Expenses	**Output**	[M]	0.53%	0.79%	0.28%	0.91%
	Cost Index	[N]	3.94%	3.94%	3.94%	3.94%
	"Productivity" Estimate	[O]	**-3.40%**	**-3.15%**	**-3.66%**	**-3.03%**
	Change in Estimate		*0.04%*	*0.04%*	*0.04%*	*0.04%*
Correction 5: Add Rate of Return on Plant	**Output**	[P]	0.53%	0.79%	0.28%	0.91%
	Cost Index	[Q]	3.31%	3.31%	3.31%	3.31%
	"Productivity" Estimate	[R]	**-2.78%**	**-2.52%**	**-3.03%**	**-2.40%**
	Change in Estimate		*0.63%*	*0.63%*	*0.63%*	*0.63%*
Correction 6: Control for Input Price Inflation	**Industry Input Prices**	[S]	3.22%	3.22%	3.22%	3.22%
	Industry Input Quantity	[T = Q - S]	0.09%	0.09%	0.09%	0.09%
	Estimated Industry MFP	[U = P - T]	**0.44%**	**0.70%**	**0.19%**	**0.82%**
	Change in Estimate		*3.22%*	*3.22%*	*3.22%*	*3.22%*
Reconcile with PEG Testimony	**PEG MFP Calculation**	[V]	**N/A**	**-0.07%**	**N/A**	**N/A**

Table 13

Alternative Kahn Method Calculations For U.S. Electric Distributors

(Average Annual Growth Rates 2008-2011)

			Output Specification				
			"Output 40/60 Weight"	"Output 60/40 Weight"	PEG Output Index 50/50	Customers Only	Capacity Only
Black & Veatch	**Output**	[A]	1.38%	1.37%	N/A	0.29%	1.97%
	Cost Index	[B]	5.93%	5.93%	N/A	5.93%	5.93%
	"Productivity" Estimate	[C = A - B]	**-4.55%**	**-4.56%**	**N/A**	**-5.64%**	**-3.96%**
Correction 1: Logarithmic Growth Rates	**Output**	[D]	1.13%	1.10%	N/A	0.28%	1.66%
	Cost Index	[E]	5.41%	5.41%	N/A	5.41%	5.41%
	"Productivity" Estimate	[F = D - E]	**-4.28%**	**-4.30%**	N/A	**-5.13%**	**-3.75%**
	Change in Estimate		*0.27%*	*0.25%*	**N/A**	*0.51%*	*0.21%*
Correction 2: Trend Indexes	**Output**	[G]	1.43%	1.31%	0.97%	0.28%	1.66%
	Cost Index	[H]	5.44%	5.44%	5.44%	5.44%	5.44%
	"Productivity" Estimate	[I = G - H]	**-4.01%**	**-4.13%**	**-4.47%**	**-5.16%**	**-3.78%**
	Change in Estimate		*0.27%*	*0.18%*	*N/A*	*-0.03%*	*-0.03%*
Correction 3: "Customer Service & Information Expenses"	**Output**	[J]	1.43%	1.31%	0.97%	0.28%	1.66%
	Cost Index	[K]	5.08%	5.08%	5.08%	5.08%	5.08%
	"Productivity" Estimate	[L]	**-3.66%**	**-3.77%**	**-4.12%**	**-4.80%**	**-3.43%**
	Change in Estimate		*0.35%*	*0.35%*	*0.35%*	*0.35%*	*0.35%*
Correction 4: Add Depreciation to O&M Expenses (Black & Veatch Data)	**Output**	[M]	1.43%	1.31%	0.97%	0.28%	1.66%
	Cost Index	[N]	5.02%	5.02%	5.02%	5.02%	5.02%
	"Productivity" Estimate	[O]	**-3.59%**	**-3.71%**	**-4.05%**	**-4.74%**	**-3.36%**
	Change in Estimate		*0.06%*	*0.06%*	*0.06%*	*0.06%*	*0.06%*
Correction 5: Add Depreciation to O&M Expenses (SNL Data)	**Output**	[P]	1.43%	1.31%	0.97%	0.28%	1.66%
	Cost Index	[Q]	4.85%	4.85%	4.85%	4.85%	4.85%
	"Productivity" Estimate	[R]	**-3.42%**	**-3.54%**	**-3.88%**	**-4.57%**	**-3.19%**
	Change in Estimate		*0.17%*	*0.17%*	*0.17%*	*0.17%*	*0.17%*
Correction 6: Add Rate of Return on Plant	**Output**	[S]	1.43%	1.31%	0.97%	0.28%	1.66%
	Cost Index	[T]	3.62%	3.62%	3.62%	3.62%	3.62%
	"Productivity" Estimate	[U]	**-2.19%**	**-2.30%**	**-2.65%**	**-3.34%**	**-1.96%**
	Change in Estimate		*1.23%*	*1.23%*	*1.23%*	*1.23%*	*1.23%*
Correction 7: Control for Input Price Inflation	**Industry Input Prices**	[V]	3.35%	3.35%	3.35%	3.35%	3.35%
	Industry Input Quantity	[W = T - V]	0.27%	0.27%	0.27%	0.27%	0.27%
	Estimated Industry MFP	[X = S - W]	**1.16%**	**1.05%**	**0.70%**	**0.01%**	**1.39%**
	Change in Estimate		*3.35%*	*3.35%*	*3.35%*	*3.35%*	*3.35%*
Reconcile with PEG Testimony	**PEG MFP Calculation**	[Y]	**N/A**	**N/A**	**N/A**	**0.90%**	**N/A**

We next replace the trend in net plant value with the trend in the *return* on net plant value by multiplying net plant value by a ROR. The ROR is calculated from estimates of the allowed return on equity and in the embedded cost of debt which we calculated using data from SNL and its Regulatory Research Associates affiliate. With this upgrade, the return on rate base can be added to operating expenses and there is no need for the complication of a cost trend *index*. This step further also raises the MFP trend estimate considerably, to **-2.78%.**[19]

As a final correction, we convert the negative of the unit cost trend into a bona fide (if inexact) MFP index by adding our own estimate of the input price trend of the gas distribution industry for the 2008-2011 sample period, as reported in Table 3 above. Recall that our index features a consistent approach to capital cost measurement. As we might expect, this raises the average annual growth in the MFP estimate substantially, to a positive **0.44%**. A positive trend estimate is also obtained using all of the alternative output metrics. Bearing in mind the flaws of the B&V methodology even as corrected, it can still be said that these results are consistent with our estimate of a **0.96%** *long* run gas distribution productivity trend

Turning next to B&V's power T&D study, our first correction is once again the use of logarithmic rather than arithmetic growth rates. Using B&V's "Output 40/60 weight" index for illustrative purposes, this raises the estimated average annual growth in MFP modestly, from **-4.55%** to **-4.28%**. We next employ proper output and cost trend indexes using B&V's subindexes. This raises the estimated MFP trend modestly, to **-4.01%.** We next remove customer service and information expenses from O&M expenses, since B&V provided itemized data on these expenses on the electric side. This raises the estimated MFP trend modestly, to **-3.66%.** Using SNL's data, we next add estimates of each utility's T&D depreciation expenses to O&M expenses and use this as one of the two cost trend subindexes. The trend in net plant value now applies only to the trend in the return on plant. This also raises the MFP trend modestly, to **-3.42%.**[20]

[19] Gas corrections 5 and 6 differ slightly from those reported in our initial testimony due to a revised gas utility ROR calculation.
[20] Table 13 also contains a "Correction 4", not discussed in our initial testimony, in which we first used an estimate of depreciation expense which we computed using the B&V data.

We next replace the trend in net plant value with the trend in the return on net plant value by multiplying net plant value by an ROR computed using the same methodology we used in our gas study corrections. With this upgrade, the return on rate base can be added to operating expenses and there is no need for the complication of a cost trend index. This step raises the MFP trend estimate substantially, to **-2.19%.**

As a final correction, we convert the negative of the unit cost trend into a bona fide (if inexact) MFP index by adding our own estimate of the input price trend of the power distribution industry for the 2008-2011 sample period, as reported in Table 6 above. As we might expect, this raises the average annual growth in the MFP estimate substantially, to a positive **1.16%**. Positive trends are also achieved using other output metrics considered. Bearing in mind the short sample period and other flaws of the B&V methodology even as corrected, it can be said that the corrected results are consistent with our estimate of a **0.93%** *long* run power distribution productivity trend.

General Statements

B&V also make some general comments about MFP in their reports that should be addressed.

- The authors state (gas report pp. 3-4) that "under the traditional view of capital, depreciation measures the decline in productivity from using an asset over time. For the bulk of gas distribution and transmission, the productive capacity does not change over time. That is, the capacity of a segment of pipe remains the same over its life." It is possible that this is true, and such an observation might be pertinent in the design of a cost benchmarking study. Under cost of service regulation, however, the value of a utility plant addition depreciates over the life of plant. This depreciation substantially reduces growth in a utility's revenue requirement and should be captured in productivity research supporting X factor calibration. It is certainly captured by the Kahn method. Capital depreciation is a force for positive capital productivity growth and accelerated MFP growth.
- The authors suggest (gas and electric reports p. 3) that "TFP is likely to be negative" because the TFP trend is dominated by the capital productivity trend and the capital productivity trend is "far more likely to be negative". They further state (gas report p. 5, electric report p. 4) that "From a theoretical view, TFP is much more likely to be

negative on a going forward basis than it is to be positive". These statements are assertions about empirical trends that are not backed up by facts. It is remarkable that the same statement is made for both industries since it by no means clear that the need for system modernization is the same in both industries.

The research we detailed in Sections 3 and 4 has shown that the long-run MFP and capital productivity trends of gas and electric distributors are both positive. MFP growth was slightly negative for gas distributors in the unusual 2008-11 period, but this was due to declining *O&M* productivity. Capital productivity growth remained positive. Our research suggests that normal levels of replacement capex do not preordain negative capital or multifactor productivity growth. Multifactor and capital productivity growth may be negative "during periods of significant infrastructure replacement." However, it is also true that the rate of depreciation is more rapid for an older system in the absence of accelerated system modernization. Furthermore, the impact of such programs on the MFP growth of gas distributors can be appreciably offset by more rapid O&M productivity growth.

- The authors suggest (*e.g.* gas report pp. 2-3) that usage variables such as the delivery volume have no place in a TFP study because they have little cost impact. These comments undermine the validity of NERA's Alberta study, which produced a substantially higher TFP trend estimate than B&V's study yielded. Our analysis in Section 2.2 suggests a more nuanced view. Volume variables *should* feature prominently in a productivity study used to design a *price* cap index because the issue in PCI design is the difference between the trends in cost and billing determinants, and volumes are important billing determinants. In Alberta, power distributors were proposing PCIs. Furthermore, numerous econometric studies have found delivery volumes to be a statistically significant driver of energy distributor cost in the long run.

- The authors stress (gas report p. 11) that their results "represent a more comprehensive review of costs than that found in (NERA's) AUC analysis." However, they make no persuasive case (on p. 6-8 of the gas and electric reports) that NERA's exclusion of A&G expenses or "equipment used to maintain the delivery system" would result in a substantial overestimation of the *trend* in the productivity associated with gas delivery services." Both expense categories are fairly small when pension and benefit expenses are excluded. While it is true that A&G expenses are to a large degree labor related, even B&V note that labor productivity growth exceeded capital productivity growth on balance.

- The authors note (gas and electric reports p. 4) the negative trend after 1999 in power distribution MFP in NERA's Alberta study, and state that "this roughly corresponds to the period when broad-based infrastructure replacement programs were being implemented by gas and electric utilities." They go on to state on p. 4 that "the AUC approach to measurement of TFP is flawed and produces unreliable, biased results."

  In response, we note first that B&V has provided no evidence of an uptick in power distribution infrastructure replacement programs during these years. Their use of the same statement for both industries is once again remarkable.

  As for the quality of the NERA study, we were actively involved in the AUC PBR proceeding and agree that the study had flaws. As B&V notes, the negative productivity trend during this period was due in part to the use of a volumetric index during a period that ended in a severe recession. There were additionally other aspects of the methodology (such as the use of a multilateral input quantity index rather than a chain-weighted index) that distorted results for the later years of the sample period. However, the NERA index was designed for use with a long sample period and the long-term MFP trend reported by NERA is similar to that which we have calculated and reported in Section 4. NERA did acknowledge one error in its work in the Alberta proceeding and provided a correction. Ironically, their admitted error was to measure the trend in the labor *quantity* of power distributors as the trend in their labor *cost.*

- Finally, the authors state (gas and electric reports p. 11) that "TFP results derived from [their] study are theoretically sound and produce results consistent with the logical foundations of TFP analysis…." We have in fact showed that the opposite is true. The B&V productivity results are in fact theoretically *unsound* and produce results that are *inconsistent* with the logical foundations of TFP analysis. It is important for the future of PBR in Canada that the failings of the B&V study be acknowledged and that the study be explicitly assigned no weight in the Commission's deliberations.

7. Stretch Factor

The stretch factor term of an X factor should reflect an expectation of how the productivity growth of the subject utility will differ from the base productivity growth target. This depends in part on the company's operating efficiency at the start of the PBR plan. It also depends on how the performance incentives generated by the PBR plan compare to those in force for sampled utilities during the index sample period.

Both Fortis units have operated under PBR in the past. However, the PBR plans for both companies exempted a large portion of capital cost from the force of PBR, and both companies have now operated for a few years under cost of service regulation. Neither company has presented convincing evidence of superior operating performance in this proceeding. On the basis of the available evidence, it is reasonable to assume that each company is an average cost performer.

Each company is proposing a PBR plan with a five-year term. An earnings sharing mechanism ("ESM") would share all surplus and deficit earnings 50/50 between each Company and its customers. Meanwhile, the firms in the gas and electric utility samples averaged rate cases about every four years.

Considering all of these factors, we believe that a stretch factor of 0.20% is reasonable for each Fortis company. The need for a stretch factor is all the more imperative should the Commission approve macroeconomic inflation measures and decide not to adjust the X factors for the negative MFP trend of Canada's economy.

8. Summing Up

Our research presents the Commission with an opportunity to set X factors for a variety of ARMs, and not just the cost escalation indexes that Fortis proposes. Suppose, for example, that the Commission prefers that Fortis operate under comprehensive revenue cap indexes similar to those that apply to gas utilities in Alberta. For FEI, our research supports X factors in the [**1.16**%, **1.33%**] range. The lower bound is the sum of the estimated **0.96**% long-run MFP trend of US gas distributors and a **0.20**% stretch factor. The upper bound is the sum of the stretch factor and the estimated **1.13%** long-run MFP trend of US gas distributors when 10% of plant additions are removed.

For FBC, our research supports X factors in the [**1.13**%, **1.38%**] range. The lower bound is the sum of the estimated **0.93**% long run MFP trend of US power distributors and a **0.20**% stretch factor. The upper bound is the sum of the estimated **1.18%** long run MFP trend of US power distributors when 10% of plant additions are removed.

Suppose next that the Commission prefers to have separate cost targets for O&M expenses and some notion of capital cost. Our research provides a reasonable X factor for capital cost but not for capex.

For FEI, our research supports an X^{OM} factor of **1.18**%. This is the sum of the estimated **0.98**% long-run O&M productivity trend of US gas distributors and a **0.20%** stretch factor. For FBC, our research supports an X^{OM} factor of **1.71**%. This is the sum of the estimated **1.51**% long-run O&M productivity trend of US power distributors and a **0.20**% stretch factor.

With respect to capital cost, we have shown that it is difficult to establish X factors that are applicable to capital *spending*. A sensible alternative is an escalator for the cost of capital. Our research suggests that the X factor for the cost of capital of FEI should lie in the [**1.18%**, **1.54%**] range. The lower bound of this range is the sum of the estimated **0.98%** long-run trend in the capital productivity of US gas distributors and a **0.20%** stretch factor. The upper bound is the sum of the same stretch factor and the estimated **1.34%** long-run trend in the capital productivity of US gas distributors when 10% of plant additions are removed.

Our research suggests that an X factor for the cost of capital of FBC should lie in the [**0.81%**, **1.25%**] range. The lower bound of this range is the sum of the estimated **0.61%** long-run trend in the capital productivity of US power distributors and a **0.20%** stretch factor. The upper bound is the sum of the same stretch factor and the estimated **1.05%** long-run trend in the capital productivity of US power distributors when 10% of plant additions are removed.

APPENDIX

This Appendix contains more technical details of our empirical research for the CEC. Sections A.1 and A.2 discuss our input quantity and productivity indexes, respectively. Section A.3 addresses our method for calculating input price inflation. Section A.4 discusses the calculation of capital cost.

A.1 INPUT QUANTITY INDEXES

The growth rate of a summary quantity index is defined by a formula that involves subindexes measuring growth in the prices of various kinds of inputs. Major decisions in the design of such indexes include their form and the choice of input categories and quantity subindexes.

A.1.1 Index Form

The growth of the gas distribution O&M quantity input index was the difference between the growth in applicable total cost and the growth of an O&M input price index. Each summary input quantity index was of Törnqvist form.[21] This means that its annual growth rate was determined by the following general formula:

$$\ln\left(\frac{Inputs_t}{Inputs_{t-1}} \right) = \sum_j \frac{1}{2} \cdot \left(sc_{j,t} + sc_{j,t-1} \right) \cdot \ln\left(\frac{X_{j,t}}{X_{j,t-1}} \right). \qquad [A1]$$

Here in each year *t*,

$Inputs_t$ = Summary input quantity index

$X_{j,t}$ = Quantity subindex for input category *j*

$sc_{j,t}$ = Share of input category *j* in the applicable cost.

It can be seen that the growth rate of the index is a weighted average of the growth rates of the input quantity subindexes. Each growth rate is calculated as the logarithm of the ratio of the quantities in successive years. Data on the average shares of each input in the applicable cost of each utility in the current and prior years served as weights.

[21] For seminal discussions of this index form, see Törnqvist (1936) and Theil (1965).

A.1.2 Input Quantity Subindexes

General Comments

The approach used in this study to measure trends in input quantities relies on the theoretical result the growth rate in the cost of any class of input *j* is the sum of the growth rates in appropriate input price and quantity indexes for that input class.

Electric

The quantity subindex for labor was the ratio of salary and wage expenses to a regionalized labor price index. The growth rate of the labor price index was calculated for most years as the growth rate of the national employment cost index ("ECI") for the salaries and wages of the utility sector of the U.S. economy plus the difference between the growth rates of multi-sector ECIs for workers in the utility's service territory and in the nation as a whole.[22] The quantity subindex for other O&M inputs was the ratio of the expenses for these inputs to an M&S price index using price subindexes for power distributor M&S inputs obtained from the Global Insight Power Planner service.

A.2 PRODUCTIVITY GROWTH RATES AND TRENDS

The annual growth rate in each productivity index is given by the formula

$$\ln\left(\frac{Productivity_t}{Productivity_{t-1}}\right)$$
$$= \ln\left(\frac{Output\ Quantities_t}{Output\ Quantities_{t-1}}\right) - \ln\left(\frac{Input\ Quantities_t}{Input\ Quantities_{t-1}}\right). \qquad [A3]$$

The long-run trend in each productivity index was calculated as its average annual growth rate over the full sample period.

A.3 INPUT PRICE INDEXES

The growth rate of a summary price index is defined by a formula that involves subindexes measuring growth in the prices of various kinds of inputs. Major decisions in the design of such indexes include their form and the choice of input categories and price subindexes.

[22] Utilities no longer report on their FERC Form 1 the number of workers that they employ.

A.3.1 Price Index Formulas

The summary input price indexes used in this study are of Törnqvist form. This means that the annual growth rate of each index is determined by the following general formula:

$$\ln\left(\frac{Input\ Prices_t}{Input\ Prices_{t-1}} \right) = \sum_j \frac{1}{2} \cdot \left(sc_{j,t} + sc_{j,t-1} \right) \cdot \ln\left(\frac{W_{j,t}}{W_{j,t-1}} \right). \quad [A4]$$

Here in each year *t*,

$Input\ Prices_t$ = Input price index

$W_{j,t}$ = Price subindex for input category *j*

$sc_{j,t}$ = Share of input category *j* in applicable total cost.

The growth rate of the index is a weighted average of the growth rates of input price subindexes. Each growth rate is calculated as the logarithm of the ratio of the subindex values in successive years. The average shares of each input group in the applicable cost of each utility during the two years are the weights.

A.3.2 Input Price Subindexes and Costs

Gas

The O&M input price indexes summarized trends in the prices of labor and M&S inputs. Price subindexes for the M&S inputs of US gas utilities were obtained from the Global Insight Power Planner service. The price subindex for capital is discussed in Appendix Section 4. The labor price index was developed in manner similar to that described for the power research.

Electric

The price subindexes were the same as those described in Appendix Section A-1. The cost shares were the same as those discussed in Section 3.2.1

A.4 THE COS APPROACH TO CAPITAL COST MEASUREMENT

A.4.1 Derivation

The COS approach to capital cost measurement was used in our index research. Here is the mathematical derivation of our COS formulas. For each year, t, of the sample period let

ck_t = Total non-tax cost of capital

$ck_t^{Opportunity}$ = Opportunity cost of capital

$ck_t^{Depreciation}$ = Depreciation cost of capital

VK_{t-s}^{add} = Gross value of plant installed in year t-s

WKA_{t-s} = Unit cost of plant installed in year t-s (the "price" of capital assets)

a_{t-s} = Quantity of plant additions in year $t-s = VK_{t-s}^{add} / WKA_{t-s}$

xk_t = Total quantity of plant available for use and that results in year t costs

xk_t^{t-s} = Quantity of plant available for use in year t that remains from plant additions in year t-s

VK_t = Total value of plant at the end of last year

N = Service life of utility plant

r_t = Rate of return (cost of funds)

WKS_t = Price of capital service

A few assumptions are made for convenience in the derivation to follow:

(1) All kinds of plant have the same service life N.

(2) Full annual depreciation and opportunity cost are incurred in year t on the amount of plant remaining at the end of year t-1, as well as on any plant added in year t.

(3) The ARM is not designed to recover changes in taxes.

Consider, now, that the non-tax cost of capital under cost of service regulation is the sum of depreciation and the opportunity cost paid out to bond and equity holders.

$$ck_t = ck_t^{opportunity} + ck_t^{depreciation}$$

Assuming straight line depreciation and book valuation of utility plant,

$$\begin{aligned} ck_t &= \sum_{s=0}^{N-1} \left(WKA_{t-s} \cdot xk_t^{t-s}\right) \cdot r_t + \sum_{s=0}^{N-1} WKA_{t-s} (1/N) \cdot a_{t-s} \qquad \text{[A5]} \\ &= xk_t \cdot \sum_{s=0}^{N-1} \left(\frac{xk_t^{t-s}}{xk_t} \cdot WKA_{t-s} \right) \cdot r_t + xk_t \cdot \sum_{s=0}^{N-1} WKA_{t-s} \cdot \frac{(1/N) \cdot a_{t-s}}{xk_t}. \end{aligned}$$

where, as per assumption 2 above,

$$xk_t = \sum_{s=0}^{N-1} xk_t^{t-s}. \qquad [A6]$$

Under straight line depreciation we posit that in the interval $[(t-(N-1)),(t-1)]$,

$$xk_t^{t-s} = \frac{N-s}{N} \cdot a_{t-s}. \qquad [A7]$$

Combining [A6] and [A7] we obtain a capital quantity index that is a perpetual inventory equation.

$$xk_t = \sum_{s=0}^{N-1} \frac{N-s}{N} \cdot a_{t-s}. \qquad [A8]$$

The size of the addition in year t-s of the interval (t-1, t-N) can then be expressed as

$$a_{t-s} = \frac{N}{N-s} \cdot xk_t^{t-s}. \qquad [A9]$$

Relations [A5] and [A9] together imply that,

$$\begin{aligned} ck_t &= xk_t \cdot \sum_{s=0}^{N-1} \left(\frac{xk_{t-1}^{t-s}}{xk_t} \cdot WKA_{t-s} \right) \cdot r_t + xk_t \cdot \sum_{s=0}^{N-1} \frac{xk_t^{t-s}}{xk_t} \cdot WKA_{t-s} \cdot \frac{1}{N-s} \qquad [A10] \\ &= xk_t \cdot WKS_t. \end{aligned}$$

Here,

$$WKS_t = \sum_{s=0}^{N-1} \frac{xk_{t-1}^{t-s}}{xk_t} \cdot WKA_{t-s} \cdot r_t + \sum_{s=0}^{N-1} \frac{xk_t^{t-s}}{xk_t} \cdot WKA_{t-s} \cdot \frac{1}{N-s}. \qquad [A11]$$

Relation [A10] reveals that the cost of capital under COS regulation can be decomposed into a capital price index and a capital quantity index. The capital service price in a given year reflects a weighted average of the capital asset prices in the N most recent years (including the current year). The weight for each year, t-s, is the estimated share, in the total amount of plant that contributes to cost, of plant remaining from additions in that year. This share will be larger the more recent the plant addition year and the larger were the plant additions made in that year. The average asset price rises over time as the price for each of the N years is replaced with the higher price for the following year. It will reflect inflation that occurred in numerous past years as well as current inflation. Note also that the depreciation rate varies with the age of the plant. For example, the depreciation rate in the last year of an asset's service life is 100%.[23]

A.4.2 Implementation

Gas Distribution

Relations [A8] and [A11] were calculated for each sampled utility for a single, comprehensive class of assets. In these calculations, regional Handy-Whitman indexes of construction costs were used as the asset price trend indexes.[24] The value of N was set at 41. The values for gross plant additions VK_{t-s}^{add} in the years 1995-2011 were obtained from SNL Financial. Values for earlier years were imputed using data on the net value of plant in 1994 and the construction cost index values for those years.

The calculation of [A11] requires, in addition, an estimate of the rate of return trend.[25] We employed a weighted average of RORs for debt and equity. For debt we calculated the average embedded cost of debt from a large sample of gas utilities, using data from SNL Financial. For the rate of return on equity we calculated the allowed rate of return from a large sample of gas utilities as reported by Regulatory Research Associates. These ROR estimates were also used in our B&V corrections.

Power Distribution

Relations [A8] and [A11] were calculated for each sampled utility for two categories of assets: distribution plant and general plant. In these calculations, regional Handy-Whitman indexes of power distribution construction costs were used as the asset price

[23] Recall that the depreciation rate is constant under the geometric decay approach to capital costing.

[24] These data are reported in the *Handy-Whitman Index of Public Utility Construction Costs*, a publication of Whitman, Requardt and Associates.

[25] This calculation was made solely for the purpose of measuring input price and productivity *trends* and does not prescribe an appropriate Rate of Return *level* for Fortis in this proceeding.

indexes.[26] In the distribution index the value of N was set at 44. The value of N for general plant was set at 16 years. The values for gross plant additions VK_{t-s}^{add} in the years 1965-2011 were drawn from FERC Form 1. Values for earlier years were imputed using data on the net value of plant in 1964 and the construction cost index values for those years. The same ROR methodology was used in the electric calculations as was used in the gas calculations.

[26] These data are reported in the *Handy-Whitman Index of Public Utility Construction Costs*, a publication of Whitman, Requardt and Associates.

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BOARD STAFF RESPONSE TO UNDERTAKING OF ENBRIDGE

UNDERTAKING TCU1.4

REF: Tr.1 p22

TO PROVIDE THE INSTRUCTIONS PROVIDED TO DR. KAUFMANN IN CONNECTION WITH THIS PROCEEDING

RESPONSE

The contract with Pacific Economics Research LLC lists the following scope and deliverables:

1. Review the Union and Enbridge 2012-2013 IR applications;
2. Assist Board staff in developing information requests related to the IR application, and review responses by Union and Enbridge;
3. Undertake relevant analyses to assess and evaluate the proposed IR plans filed in the Union and Enbridge IR applications such as: 1) review proposed IR plans for appropriateness (e.g. are the elements of each plan appropriate), 2) identify any concerns and information gaps, and 3) conduct other analysis as required, which may include responding to the benchmarking reports previously filed in Enbridge's recent CoS application by Concentric Energy Advisors (CEA) and Power System Engineering (PSE);
4. Review stakeholder input and provide comment as to relevancy; and
5. Testify on its research, analysis and findings before the Board.

BOARD STAFF RESPONSE TO UNDERTAKING OF EGDI

UNDERTAKING TCU1.5

REF: Tr.1 p25

DR. KAUFMANN TO PROVIDE THE ALGORITHM USED TO RUN SCENARIOS, OR ACCESS TO IT; MORE PRECISELY, THE SAMPLE MEAN VALUES FOR INDEPENDENT VARIABLES AND THE SAMPLE MEAN FOR COSTS

RESPONSE

A copy of the Benchmarking "Algorithm" is attached. PEG developed this algorithm to simulate benchmarking results for Ontario's electricity distributors using the same econometric model that is used to assign stretch factors for these distributors.

The 2002 - 2012 sample mean values, across all 73 distributors, for distribution costs and the independent variables used in the econometric model are provided below:

- Total distribution costs: $41,914,468
- Capital service price: 17.389
- Number of customers: 63,344
- System capacity peak demand: 3,448,215 KW
- Retail deliveries: 1,629,428.323 kWh
- Average line length: 2,718 km
- Percent of 2012 customers added in last 10 years: 12.86%

Witness: Dr. Lawrence Kaufmann, PEG

BOARD STAFF RESPONSE TO UNDERTAKING OF EGDI

UNDERTAKING TCU1.6

REF: Tr.1 p26

DR. KAUFMANN TO PROVIDE A RESPONSE TO EGDI'S QUESTION NO. 1

RESPONSE

Puget Sound Energy and Wisconsin Gas were excluded from the econometric analysis because, during the sample period, both companies went from being stand-alone gas distributors to combination gas and electric utilities as a result of mergers.

PEG's econometric model included number of electric customers as an independent variable to reflect economies of scope that distributors can attain by serving gas and electric customers simultaneously. The sample used to estimate PEG's econometric model included both stand-alone gas utilities and combination gas-electric utilities. However, Puget Sound Energy and Wisconsin Gas were the only utilities that transitioned from being stand-alone to combination utilities during the sample period. As a result, the reported numbers of electric customers for each company changed from zero to positive during the sample period that was being used to estimate the model.

PEG believed that this constituted a structural change which was unique to these two utilities. Structural changes can impact the coefficients estimated in econometric models. Because the US gas distribution as a whole did not experience such a structural break during the sample period, PEG believed it was appropriate to exclude these two utilities when estimating the industry-wide coefficients in the econometric analysis.

Witness: Dr. Lawrence Kaufmann, PEG

BOARD STAFF RESPONSE TO UNDERTAKING OF EGDI

UNDERTAKING TCU1.7

REF: Tr.1 p32

DR. KAUFMANN TO PROVIDE WRITTEN MATERIALS THAT SUPPORT HIS VIEW REGARDING THE RELATIONSHIP BETWEEN FROST HEAVE AND DIFFERENT GAS DISTRIBUTION PIPE MATERIALS

RESPONSE

Please see the attached February 2012 White Paper "Distribution Pipeline System Integrity Threats Related to Cold Weather," prepared by Kiefner & Associates Inc. In the Summary and Conclusions section of this paper (pp. 1-2), they write:

> "Cold weather-related incidents have occurred in gas distribution systems, gas transmission systems, and hazardous liquid transmission systems. By far the most common cause of such incidents is frost heave, acting on buried pipe…All types of pipe materials found in distribution service have been affected, however piping with certain attribute appear to have higher-than-average susceptibility. These are:
>
> - Cast iron pipe
> - Pipe of unknown material type
> - Steel pipe installed prior to 1950
>
> Integrity Management (IM) principles require that the operator consider integrity threat interaction. Frost heave or snow load might be readily tolerated by some materials or piping systems in sound condition, while low-ductility materials or pipe joints made by vintage techniques may remain reliable absent certain outside forces, however, when these circumstances exist simultaneously the likelihood of a failure is significantly greater. Systems of the type listed above in locations susceptible to frost heave therefore represent potential interacting-threat situations.
>
> Piping systems having the attributes listed above and located in areas known or suspected to be susceptible to frost heave or thaw settlement should be identified and considered for condition monitoring or mitigation

Witness: Dr. Lawrence Kaufmann, PEG

> activities…Mitigations could include but are not limited to: replace iron pipe, unknown-material pipe, and threaded steel pipe, with plastic or welded steel pipe in locations known or suspected to be susceptible to frost heave."

This summary discussion, and the analysis that follows, supports Dr. Kaufmann's opinion that the consequences of frost heave for system integrity and gas leaks are associated more with cast iron and bare steel gas distribution main than plastic/polyethylene main. In fact, the authors say that actions for mitigating the effects of frost heave on distribution systems include replacing cast iron and threaded steel pipe with plastic pipe.

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KIEFNER WHITE PAPER, FEBRUARY 2012

Distribution Pipeline System Integrity Threats Related to Cold Weather

MJ Rosenfeld, PE and M Van Auker

Introduction

Cold weather can produce threats to the integrity of distribution pipeline systems. Integrity management (IM) concepts required an operator to identify integrity threats as a necessary step to prioritizing integrity assessments, and developing mitigations. This report discusses the most common integrity threats caused by cold weather and identifies the attributes of the most susceptible systems. This information should enable a gas distribution system operator to develop appropriate decision processes to address cold weather risks in the context of its distribution IM program.

Summary and Conclusions

Cold weather-related incidents have occurred in gas distribution systems, gas transmission systems, and hazardous liquid transmission systems. By far the most common cause of such incidents is frost heave, acting on buried pipe. However, a large number of less-frequent incident scenarios related to cold weather have been described in PHMSA's reportable incident database, affecting both buried and above-ground installations. All types of pipe materials found in distribution service have been affected, however piping with certain attributes appear to have higher-than-average susceptibility. These are:

- Cast iron pipe
- Pipe of unknown material type
- Steel pipe installed prior to 1950

Applus RTD

IM principles require that the operator consider integrity threat interaction. Frost heave or snow load might be readily tolerated by some materials or a piping system in sound condition, while low-ductility materials or pipe joints made by vintage techniques may remain reliable absent certain outside forces, however, when these circumstances exist simultaneously the likelihood of a failure is significantly greater. Systems of the type listed above in locations susceptible to frost heave therefore represent potential interacting-threat situations.

Piping systems having the attributes listed above and located in areas known or suspected to be susceptible to frost heave or thaw settlement should be identified and considered for condition monitoring or mitigation activities. While frost heave was responsible for the largest number of incidents, other causes have also been identified, including snow and ice falls from rooftops, confined freezing of water trapped in components, or build-up of ice where standing water accumulates around risers or under low-mounted above-ground components.

Condition monitoring could involve a range of activities, including but not limited to:

- periodic visual site inspection during cold weather months by someone qualified to recognize evidence of frost heave or thaw settlement;
- examination of piping buried above the frost line for evidence of deflection at joints during routine excavations;
- visual inspection of sites for frozen standing water around risers or under equipment mounted low to the ground.

Mitigations could include but are not limited to:

- replace iron pipe, unknown-material pipe, and threaded steel pipe with plastic or welded steel pipe in locations known or suspected to be susceptible to frost heave;
- remediate drainage or soil conditions that promote frost heave at susceptible sites;
- correct drainage conditions that promote accumulation of standing water around risers or under low-mounted equipment;
- drain trapped moisture from equipment during routine maintenance or inspections.

ANALYSIS

Cold weather effects on pipeline systems are typically classified as time independent (i.e., randomly occurring) threats. A failure caused by a time independent threat is typically incident driven such as in the case of third party damage, versus a time dependent threat which can involve deterioration of the pipeline component over time by some mechanism such as corrosion or cracking. With exposure to cold weather, the pipeline system can be threatened by a number of circumstances that can cause excessive stress or strain to produce a failure in the pipeline components. Some of these threats include frost heave, loads on pipeline components due to snow and ice accumulation, erosion due to snow and ice melts, thermal stresses due to extreme cold temperatures, and confined expansion of freezing water within components.

Causes of Distribution System Incidents

The Pipeline Hazardous Material Safety Administration (PHMSA) has collected pipeline failure data for distribution pipeline operations in the United States. This data shows that pipeline failures due to natural forces account for approximately 5.8% and 5.9% of the failures reported in 2010 and 2011, shown in Figure 1.[1]

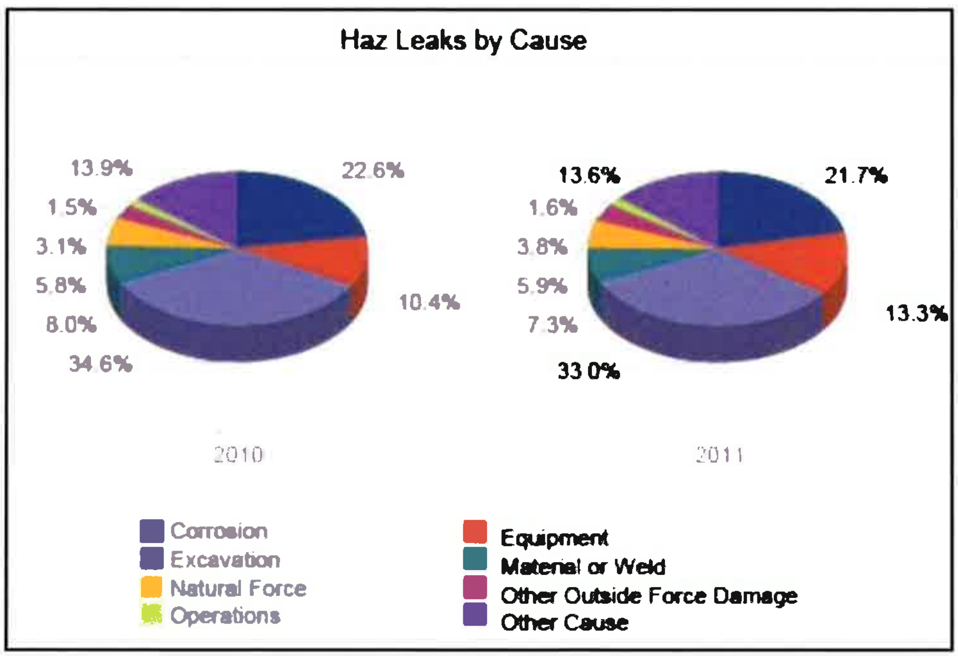

Figure 1. Hazardous Leaks on Distribution Systems by Cause

[1] www.phmsa.dot.gov

The natural force damage category includes incidents resulting from earth movement, earthquakes, landslides, subsidence, lightning, heavy rains/floods, washouts, flotation, mudslides, scouring, temperature, frost heave, frozen components, high winds, and weather events including cold weather. Closer analysis of the PHMSA data for leaks caused by natural force damage provides a better understanding of how cold weather can impact the integrity of distribution pipeline systems. The PHMSA data included 120 leak incidents on distribution systems reported to be associated with cold weather failure as a cause, Figure 2. The failure cause most frequently reported was frost heave, followed by failures due to snow accumulation and movement.

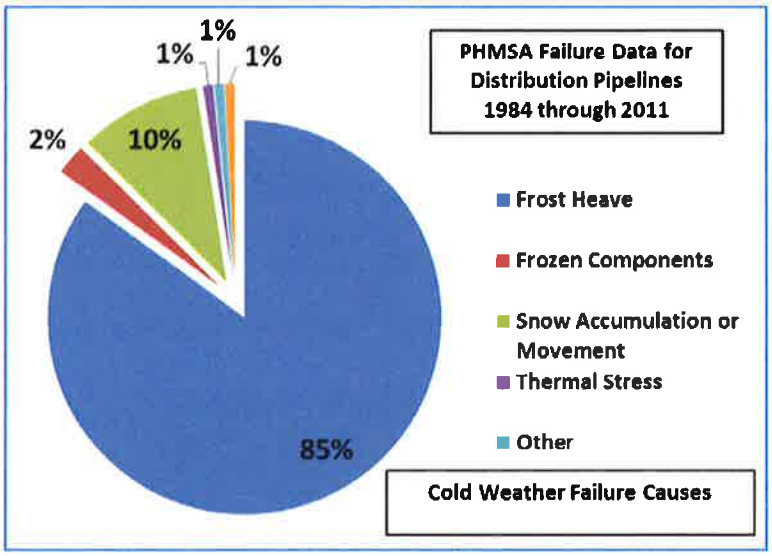

Figure 2. PHMSA Cold Weather Failure Causes

About Frost Heave

Frost heave results from ice forming beneath the surface of soil during freezing conditions in the atmosphere. The ice grows in the direction of heat loss (vertically toward the surface), starting at the freezing front or boundary below the soil surface. It requires an unfrozen water supply (usually below the frozen soil) to keep feeding the ice crystal growth. The growing ice is restrained by overlying soil, which applies a load that limits its vertical growth and promotes the formation of a lens-shaped body of ice within the soil. The growth of ice lenses continually consumes the rising water at the freezing front. The soil through which water passes to feed the formation of ice lenses must be sufficiently porous to allow capillary action, but not so porous as to break capillary continuity. Such soil is referred to as "frost heave susceptible".[2] Two common criteria for susceptibility are more than 10% of soil particles being finer than 0.075 mm, or more than 3% of particles being finer than 0.020 mm. Considering particle size alone does not account for the effects of variables such as the presence of ground water or the presence of dissolved salts or other substances which can alter the freezing state. A more comprehensive test[3] would be required in the event that precise information about susceptibility is required. Visible vertical displacement of the ground surface or effects on pavement would be consistent with the occurrence of frost heave. The resulting earth movement associated with frost heave can be significant and can impose strain on pipeline components impacted by the movement.

The primary structural integrity impact to pipeline systems as a result of frost heave is excessive longitudinal stress due to the displacement strain imposed by the earth movement. The likelihood of a failure due to frost heave may be increased when other threats exist such as circumferential stress-corrosion cracking or low-quality girth welds or threaded connections. The susceptibility of a pipeline system to damage by frost heave can be assessed by considering some key factors.

- The soil type in which the pipeline is laid. Silty and loamy types of soils would be an example of frost susceptible soil while clay or clean sand and gravel are examples of soils not susceptible to frost heave.

- The depth that a pipeline is buried. Lines buried below the frost line of a geographical area would be less susceptible to impact from frost heave since the earth movement is typically in the vertical direction and occurs above the frost line.

- Pipeline material and specification, or method of construction. The ability of a pipeline to withstand high longitudinal stress or strain may affect its likelihood for failure due to the impact of frost heave.

- The flexibility of above ground installations in frost heave susceptible areas.

The combinations of factors discussed above indicate that failure due to frost heave and other cold-weather effects represents probable interacting threat circumstances.

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[2] Andersland, O.B. and Ladanyi, B., Frozen Ground Engineering, 2nd Ed., ASCE and J. Wiley & Sons Inc., 2004.
[3] ASTM D5918, "Standard Test Methods for Frost Heave and Thaw Susceptibility of Soils", 2006.

Interacting threats are understood to occur where the probability of failure due to specific factors is significantly greater than the sum of individual probability of failure (as a proxy for "risk") from the factors occurring independently. Frost heave or snow loads, while not desirable, may be readily tolerated by ductile materials and or better-quality joints between pipes. Likewise, low-ductility materials or artifacts of vintage pipe construction technology, while not optimal, may not present a threat where normal internal pressure is the only significant load. However, certain combinations of materials in conjunction with cold weather effects may create a more acute situation than either set of circumstances do separately. This is demonstrated in the following analysis of data to identify specific attributes of piping that appear to enhance susceptibility to cold weather effects, as evidenced by high incident rates relative to the representation in the pipeline mileage fleet.

Cold Weather Failure Data

Analysis of the PHMSA reported incident data provides additional insight to the types of distribution systems that have reported failures due to cold weather effects. The data was evaluated in terms of:

- Location
- Era of installation
- Affected material
- Affected component
- Size of pipe

The results of the data analysis are discussed below. We focused on reported incident data for natural gas distribution systems, which includes mains and services. We also reviewed incident data for gas transmission systems and hazardous liquid transmission systems. With the exception of certain features unique to distribution systems (e.g. cast iron or plastic piping), the data from incidents in those systems told a similar story to the data from gas distribution systems. However an analysis of the non-distribution system data is not presented here.

The reporting interval for the data we reviewed was 1984 through 2011. During that time there were 120 incidents associated with cold weather, 95 of which were in pipe.

Location

A significant majority of the incidents affected buried pipe or components, Figure 3. This suggests that the predominant cause is related to frost heave or thaw settlement. A large proportion of those underground were also reported as under pavement.

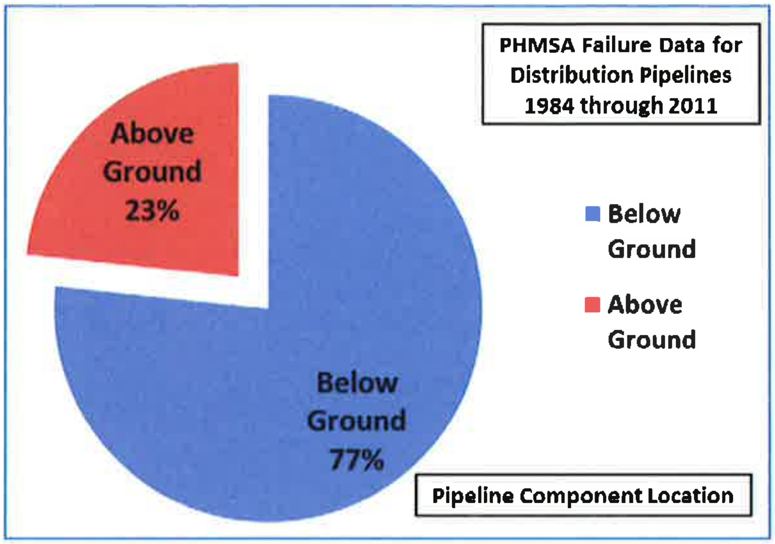

Figure 3. Cold Weather Incidents by Location

Era of Installation

The reported incidents due to cold weather were fairly evenly distributed over 20-year segments of time representing different periods of installation, from 1910 to the present, Figure 4, except that the era from 1950 to 1969 had approximately twice as many incidents as other eras.

It was thought that the larger number of incidents for 1950-1969 vintage pipe may reflect the large proportion of pipe in service installed during that time. In order to understand whether certain vintages of pipe have high or low susceptibility, the proportion of incidents attributed to specific decades of installation were compared to their representative proportions of mains miles in service nationally, listed in Table 1.

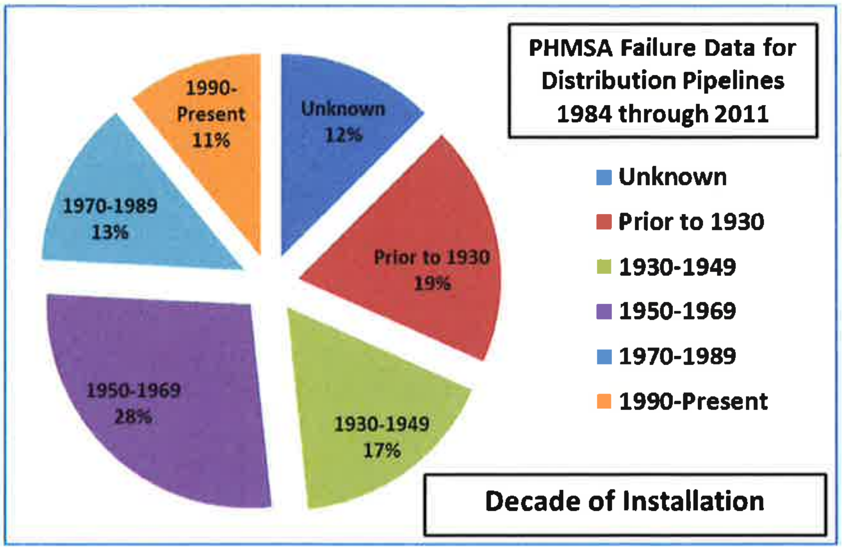

Figure 4. Cold Weather Incidents by Era of Installation

Table 1. Cold Weather Incidents and Mains Mileage by Installed Decade

Installed Decade	Incidents	% Incidents	Mains Miles	% Miles	Relative Rate
Unknown[(a)]	15	12.5%	84,736	7.0%	1.784
Pre-1940	33	27.5%	68,350	5.7%	4.866
1940 – 1949	10	8.3%	25,979	2.1%	3.880
1950 -1959	17	14.2%	107,757	8.9%	1.590
1960 – 1969	16	13.3%	196,394	16.2%	0.821
1970 – 1979	9	7.5%	131,311	10.9%	0.691
1980 – 1989	7	5.8%	155,571	12.9%	0.454
1990 – 1999	4	3.3%	232,657	19.2%	0.173
2000-Present	9	7.5%	206,731	17.1%	0.439

(a) Unknown includes both unreported and undocumented

A high susceptibility would be indicated by the ratio of the proportion of incidents normalized to the proportion of mains mileage being greater than 1.0; similarly, low susceptibility would be indicated by a ratio less than 1.0. This ratio is presented in Table 1 under the "Relative Rate" heading and is shown in Figure 5.

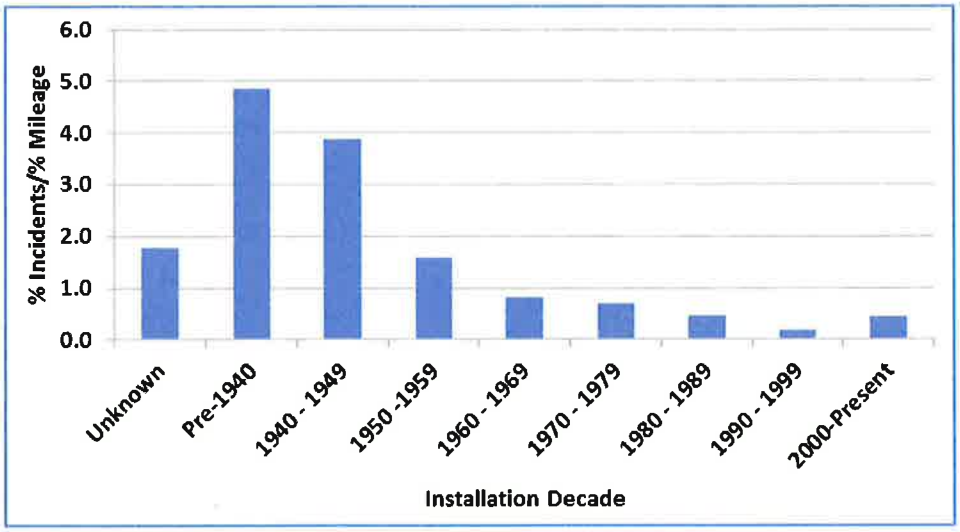

Figure 5. Normalized Susceptibility by Installed Decade

The results show that pipe installed earlier than 1950 have disproportionately high susceptibility to problems from cold weather. This is also true for pipe of unknown vintage, and pipe installed after 1950 but before 1960, but not to the extent of the pre-1950 pipe. The greater susceptibility of pre-1950 pipe is postulated to be due to two key factors. One would be the generally poor low-temperature ductility of the steels of the era which tended to have high carbon content, high sulfur content, or large-grained microstructures. The other would be the methods used to join pipe in that era, including early electric arc welds, acetylene welds, couplings, or threaded collars, all of which could have limited strength or ductility. Systems newer than 1960 exhibited comparatively lower susceptibility due to better pipe products and better quality girth welds.

Affected Materials and Components

Identified materials associated with the cold weather incidents were steel, plastic, iron, other, and unknown.[4] The systems reporting the highest number of failures were constructed of steel and cast or wrought iron, representing 40% and 42% of the incidents, respectively. Plastic and other materials represented low numbers of instances, representing 7% and 8%, respectively.

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[4] "Unknown" includes the category of not reported on the F7100.1-1 annual data reporting form, which may or may not mean that the information is unknown by the operator. The material is supposed to be specified by the operator if "other" is selected.

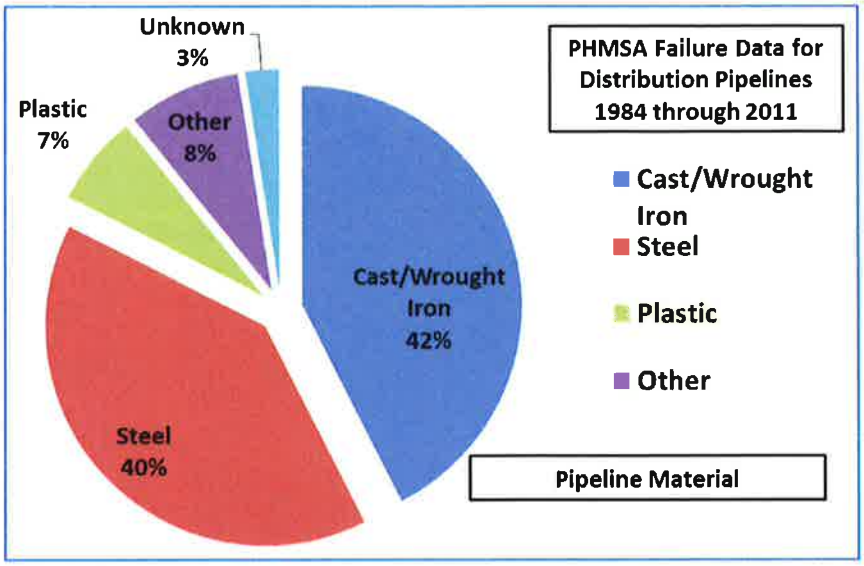

Figure 6. Cold Weather Incidents by Affected Material

However, these numbers do not appropriately describe relative susceptibility. Table 2 below lists the numbers of cold weather incidents and the number of mains miles by material type. Iron and other or unknown materials comprise very small proportions of the total mains mileage in service. The ratio of the proportion of incidents normalized to the proportion of representative miles shows extremely high susceptibility for those materials compared with steel or plastic. Steel is seen to be significantly higher than plastic, but still well below iron or the other and unknown material categories.

Table 2. Cold Weather Incidents and Mains Mileage by Material Type

Material	Incidents	% Incidents	Mains Miles	% Miles	Relative Rate
Cast/Wrought Iron	51	0.425	36,247	0.030	14.18
Steel	48	0.400	551,228	0.456	0.88
Plastic	8	0.067	620,610	0.513	0.13
Other & unknown	3	0.025	1,402	0.001	21.57

A majority of reported cold weather incidents, 58%, occurred in mains while service lines were reported in 19% of the cases, Figure 7. Meters and regulators were associated with 18% of the failures reported with most identified by causes related to snow and ice accumulation or frozen components.

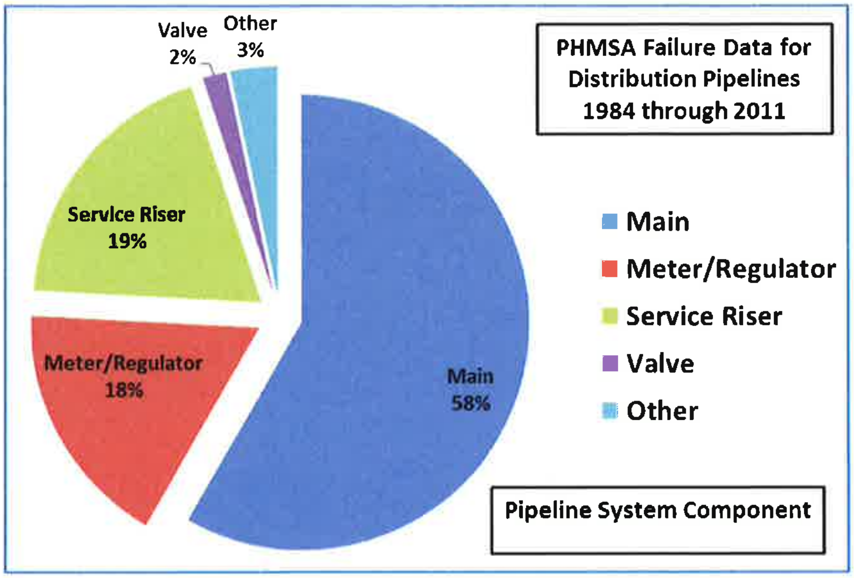

Figure 7. Cold Weather Incidents by Component

Cold Weather Incident Causes and Consequences

Cause Scenarios

A majority of the distribution systems associated with cold weather cited natural forces or outside force damage, and frequently frost heave. Other less often cited scenarios included the following, or variants thereof:

- Heavy snow or ice loads shedding off rooftops
- Damage from floating ice during flooding
- Damage from falling trees caused by ice accumulation
- Icing causing equipment or device malfunction

The PHMSA database often does not delve into the complexities of some incidents, which can only be discovered in the course of a failure investigation. Most incident reports are completed soon after an incident and before such an investigation can be completed. We are aware of a small number of incidents of near-neutral-pH stress-corrosion cracking in the threaded pipe ends of service lines, probably caused in part by frost heave or thaw settlement.[5] Only one of those incidents is identified in the PHMSA database as cold weather-related, specifically frost-heave (so the others are not

[5] A stress concentration is present at the root of the thread, acting on the axial stress induced by frost heave or settlement. A conducive environment must also be present, which might occur where a threaded joint holds moisture, oxygen in the crevice is consumed creating an anaerobic condition, and pH is in the neutral range due to lack of cathodic protection.

counted in this survey), and none are identified therein as having been affected by environmental cracking. We have also seen several incidents involving small valve bodies that fractured. These were believed to have been caused by the constrained expansion of frozen water trapped inside the valves although the direct evidence was gone (the ice was melted). We are also aware of a few incidents where the volumetric expansion of freezing water at the ground surface caused excessive reaction forces on branch connections or components. These examples illustrate the potential complexities of integrity threats associated with cold weather, or even proving that cold weather was the cause. We believe that cold weather related incidents are likely to be underreported.

Consequences

Most incidents were reported as leaks, frequently as separations of couplings or threaded joints. The isolated incidents identified as ruptures are thought to have been erroneously reported. Of the 120 distribution system incidents from 1984 through 2011, the following consequences occurred:

- 5 incidents caused 8 fatalities;
- 33 incidents caused 50 injury cases.

None of the cold weather related incidents reported for gas transmission or hazardous liquid transmission pipelines caused fatalities or injuries. This underscores the unique risk factors associated with distribution systems, namely the prevalence of gas migration paths and proximity to buildings.