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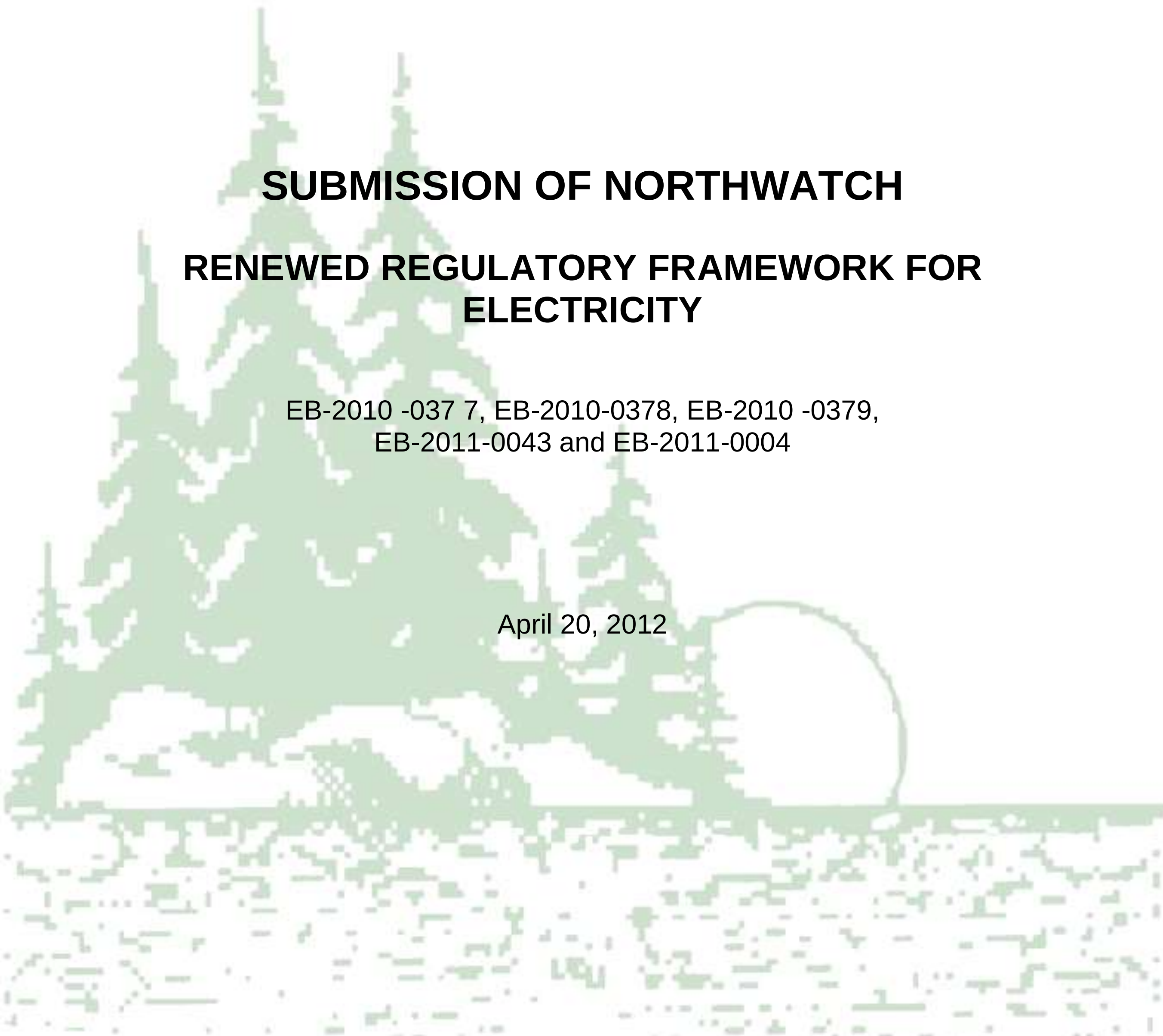

SUBMISSION OF NORTHWATCH

RENEWED REGULATORY FRAMEWORK FOR ELECTRICITY

EB-2010 -037 7, EB-2010-0378, EB-2010 -0379,
EB-2011-0043 and EB-2011-0004

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1 Introduction

Northwatch is a regional coalition of environmental and social justice /social development organizations in northeastern Ontario. It was founded in 1988 to provide a representative regional voice. Northwatch's founding members were local and district-based environmental or social justice organizations who wished to engage – among other things – in planning and policy reviews.

In 1989, with the release of Ontario Hydro's 25 Year Demand-Supply Plan, Northwatch recognized that there was a need to engage in electricity planning matters, in addition to the other natural resource and energy related concerns that had catalyzed the emergence of a coalition out of the regional networks.

Northwatch focuses on northeastern Ontario, specifically the six federal districts of Nipissing, Timiskaming, Cochrane, Sudbury, Manitoulin and Algoma, though Northwatch works at times with colleagues in northwestern Ontario on some issues, including electricity planning and nuclear waste siting concerns.

Given Northwatch's strong concern with regional planning issues, Northwatch chose to devote significant attention to the regional planning issues identified by the Board, and specifically the interface between transmission and distribution utilities to provide least-cost regional solutions. However, this submission will also speak to several other areas. The first is the need for broader regional planning of supply and demand across regions – including generation planning. Second, Northwatch addresses distribution planning issues more generally (including plans for growth, aging infrastructure, information technology and smart grid), given Northwatch's overall perspective regarding the need for planning to support sustainable development, while assuring that money is spent wisely, given the pressures on rates and customer bills in Ontario. Northwatch has also identified an issue that was left out of the Board's analysis – the necessity for incentives and plans for utility system investment to reduce energy use on the distribution systems, including reductions of distribution losses and control of customer voltage.

2 Regulatory Framework For Regional Planning for Electricity Infrastructure

2.1 Regional Planning Generally

Northwatch is a strong supporter of regional planning at the highest level.

Northwatch's core principle is that electricity planning should be done on a regional basis, with regional balance of demand and supply.

Region-specific load forecasts should be the basis for any provincial planning – to the degree that provincial planning can be of any benefit - with region-based forecasts rolled up to provide a provincial forecast; similarly, demand-supply planning should be done on a regional basis, with the outcomes rolled up to provide a provincial picture. Planning for generation and transmission should be done on an integrated regional basis. These regional plans should incorporate at a minimum load forecasts, energy efficiency and conservation, demand response, and a regional balance of demand and supply. Supply options should be selected/approved on the basis of environmental least-impacts and overall sustainability. Cost considerations should encourage efficiency and demand response to substitute for supply, including transmission and distribution projects, and should encourage integrated planning between transmission and distribution entities to prevent the undertaking of unnecessary projects.

<u>Elements of effective planning include:</u>

- Assessment of need
- Identification of alternatives
- Maximization of demand-supply balance
- Inclusion of various interests: residents, Aboriginal, other land users.

Northwatch acknowledges that regionally based electricity planning will have challenges. For example, there may be a fine line between load forecasting and industrial or economic forecasting or planning. The notable absence of any economic or industrial strategy for northern Ontario has in some instances in the past made resource management planning – forest management planning, for example – a de facto economic planning process.

2.2 Regional Planning for Local Transmission and Distribution Connection

Board Staff's paper focuses more narrowly on planning issues than Northwatch does. However, Northwatch believes that regional planning of transmission and distribution projects both in Northeastern Ontario, and elsewhere in the province, would be highly beneficial. Northwatch supports the least-cost planning of transmission and distribution projects together to meet load and resource growth. This is a good principle. It removes incentives not to co-operate and to undertake sub-optimal projects that may be too expensive or have too great an environmental or land use impact.

Northwatch believes it is important that all utilities in an area share information with each other and that there be a public process to review and vet the information, including utilities, consumer and environmental intervenors, local governments, and other interests, with the Board ultimately deciding what to include in rates. First Nations and other Aboriginal groups must have a central role in this process. We rely on the submissions of the intervenors representing Aboriginal interests to expand on this.

Northwatch also believes that engaging local communities and distribution companies and obtaining information on both municipal and Crown land use planning, is of key importance in obtaining good forecasts. Northwatch would suggest that regional planning forecasts for the transmission company and the associated assets of distributors be developed every three years for an eight year period, with the forecasts for years 6-8 prepared in less detail than the nearer term forecasts. The indicative information for years 6-8 would be expected to be less accurate, but would allow a near term plan to be changed if needed to reduce costs based on expected future growth. Requesting a forecast every five years for a period of five years also yields the potential for inaccuracy or for the need to build projects unforeseen in the last forecast period very quickly without any regulatory oversight.

A capital plan must be somewhat fluid and iterative and responsive to changed circumstances. That is one reason why we suggest a plan every three years. Moreover, it is not prudent that utilities should woodenly build what is in the approved plan if circumstances change (for example as they did due to the recent recession). In circumstances involving the North, advancement or postponement of new resource-intensive mines and industrial development or closure of existing facilities will also affect transmission and distribution investments.

Any regional planning of transmission and associated distribution assets must do a better job of load forecasting than simply drawing lines on graph paper to forecast demand. In particular, regional planning should consider any benefits of distributed generation, energy efficiency, and demand response in deferring either transmission or distribution connection assets. Northwatch supports the stakeholder presentations of Pollution Probe[1] and the Ontario Sustainable Energy Association[2], which promote use of energy efficiency and demand response in the planning process to reduce not only generation but also transmission and distribution costs. Northwatch submits that the Board Staff proposal needs to be strengthened in this area. Since area-specific efficiency and demand response is not necessarily the strength of distributors, the transmission utility and/or Ontario Power Authority should provide technical assistance to appropriate distributors to offer targeted energy efficiency and demand response which can have local benefits in project deferral along with province-wide benefits in reducing the use of energy and generating capacity.

In those winter-peaking areas where gas is available, Northwatch submits that the Board should also consider encouraging fuel switching from electricity to gas to reduce local peak loads and the need for transmission and distribution facilities. This type of work may have a longer lead time due to the need for the gas utility to connect customers or neighborhoods in some cases. The longer eight-year forecast horizon might provide insight as to where such projects would reduce transmission and distribution costs.

Northwatch provides more detailed comments under the rubric of electric distribution planning on the issue of actions that distributors can take to reduce distribution losses

[1] Jack Gibbons, Pollution Probe, Renewed Regulatory Framework for Electricity, Speaking Points (March 2012).

[2] Marion Fraser, Ontario Sustainable Energy Association, OSEA Presentation to Stakeholder Consultation for Renewed Regulatory Framework (March 2012), especially pages 4, 11, and 13.

through lines and transformers in section III below. That type of utility system efficiency needs to be factored into the regional planning process as well. Not only should distribution system efficiency be factored into the load forecasting process, but the regional planning process for local transmission and connection projects should be strengthened to include life cycle costs including line losses. Loss reductions should be considered when comparing regional projects, to give an advantage to projects that reduce losses (due to their configuration, due to the size of wires used, or due to choice of efficient substation transformers).

2.3 Payment for Regional Transmission Connection Costs

The Board Staff paper provides a number of alternatives for cost allocation for regional transmission assets to assure that the best regional cooperation can be developed.

2.3.1 Industrial Customers Should Continue Under the Current Regime

The first key issue is treatment of industrial loads. Northwatch submits that industrial customers should continue to be treated as they have been in the past – industrial customers should pay for all of their connection costs.

The Board Staff paper lays out a rationale explaining why industrial customers could be treated differently than electric distributors for transmission planning – because industrial customers have more control over planning load growth. The paper therefore suggests that even if the treatment of distributors under the Transmission System Code ("TSC") is amended the manner by which industrial customers are currently treated under the TSC is favourable, as industrial customers should remain responsible for those costs that industrial customers impose on the transmission system.[3] Northwatch supports this distinction.

Northwatch adds to Board Staff's rationale that some direct industrial loads, particularly resource-oriented loads in the North, such as mines, are more risky than typical

[3] EB 2011-043, Board Staff Discussion Paper: Regulatory Framework for Regional Planning for Electricity Infrastructure (November, 2011), pp. 16-18.

distribution loads. The risk arises from two sources. First is the potential inability of mines and resource industries to bring their own new load into service when planned due to financial and feasibility issues (which could place the transmission or distribution utility at risk of stranded costs if the project fails after electric construction begins). Second, there are uncertainties as to the length of time that the customer's mine or similar facility will operate; Xstrata's quite abrupt closing of the Kidd Metallurgical Site in Timmins[4] provides just one example. Uncertainties are not just when or if load will come in, but how long it will stay – again, this could lead us into broader discussions about industrial planning and the need for value-added and best-use policies in the natural resource sector. While those discussions may be better had with a different government agency, the electricity sector should not exacerbate problems in this area.

Board Staff's paper discusses possible mechanisms for smoothing costs.[5] If any type of stretching out of costs for industrial entities is considered beyond simply requiring up-front payment, Northwatch submits that the Alberta Utilities Commission ("AUC") Decision 2011-474 adopting what it calls Rider "I"[6] is instructive. After several years of discussion among stakeholders, the AUC adopted several mechanisms to assure that costs of short-term resource-based loads would not be stranded. These mechanisms are of critical importance for electric connections built for resource-based companies in places like Northern Ontario where project development is risky and resources underlying the project and the life of the project are uncertain (whether a single direct industrial connection or a distributor's connection driven by industrial load in a larger area). It is less necessary to adopt such mechanisms for ordinary connections of distribution utilities, because the utility will not pick up and leave, unlike a mine that closes. The Alberta requirements[7] include:

- Requiring the entity that requires the project to post the cost through the construction phase; the cost is only financed when the project comes into service.

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[4] "Xstrata closing Kidd Met Site in Timmins – 670 Jobs Lost" *North Bay Nugget*. http://www.nugget.ca/ArticleDisplay.aspx?e=2210365&archive=true.
[5] EB 2011-043, Board Staff Discussion Paper: Regulatory Framework for Regional Planning for Electricity Infrastructure (November, 2011), pp. 45-46.

[6] The letter, not the roman numeral.
[7] See Alberta Utilities Commission Decision 2011-474, pages 94-96.

- Customer must post security for the amount financed, dramatically reducing risks to other ratepayers and market participants.
- Financed amounts are paid back on a front-loaded basis that reflects an equal amount of principal every year (similar to declining utility rate base), reducing costs of a default in later years.

If smoothing of cost obligations is to be considered, Northwatch submits that same should not be implemented without the safeguards above, particularly for resource-based projects such as those in northern Ontario.

2.3.2 Other Issues Related to User Pay Principles

Northwatch is not taking a position on most of the issues relating to the potential exceptions to the user-pay principle for distributors, although we can see that some divergence from strict user-pay may be necessary in order to encourage regional solutions. However, Northwatch does wish to note three additional exceptions that Board Staff has not considered in its paper (2011-0043):

1. Section 6.3 of the TSC should be changed so that distributors are not penalized for connection costs imposed on them by local renewable energy installed under feed-in tariffs. The Board Staff paper indicates that interconnection of renewables by distributors has been increasing connection costs in recent years.[8] Northwatch submits that increasing connection costs resulting from renewables on both transmission and distribution systems, not otherwise paid by the generators themselves, should be pooled and paid province wide (either as network or local connection assets) rather than being charged to individual distributors. Northwatch submits that this process accounts for the environmental and economic benefits that all Ontarians accrue as a result of renewable energy generation.
2. If a regional project is chosen that imposes extra up-front capital costs on a distributor because of benefits in reducing a transmission company's line losses,

[8] EB 2011-043, Board Staff Discussion Paper: Regulatory Framework for Regional Planning for Electricity Infrastructure (November, 2011), p. 26.

the transmission company should compensate the distributor for those costs and collect them in its own rates. This recommendation assures that distributors will not pay extra to reduce line losses that benefit the transmitter rather than the distributor.

3. In an export scenario – if there has **not** been a balancing of demand and supply at a regional level, and extra local connection costs must be incurred within the region because of the existence of exports, those costs should not be imposed on the distributor or the transmission company's local customers, but should be passed through to the recipients of the power, i.e. the end users. Northwatch submits that this may be achieved through a network charge.

2.4 Conclusion Regarding Regional Planning

In conclusion, the OEB should:

- Require increased regional planning.
- Require distributors to provide forecast data to transmission companies every three years for an eight year time horizon (with forecasts for years 6-8 allowed to be of lesser quality than nearer term forecasts and not to be the basis for near-term action unless they point to changing the configuration of a project)
- Emphasize energy efficiency and demand response options to defer connection projects and costs in the planning process, and provide technical assistance to distributors to implement them.
- Require the regional planning process to include lifecycle costs of transmission and distribution losses in the planning project to properly value projects that reduce losses.
- Continue the status quo responsibility for direct service industrial customers to pay connection costs.
- Pool connection costs arising from renewables on the distribution and transmission systems (to the extent that the costs cannot be collected from the generators themselves) on a province-wide basis.

- Charge extra costs that would otherwise be charged to distributors arising from regional planning decisions to reduce transmission line losses to the transmission company's customers.
- Charge extra costs to distributors that are caused by exports from a region to the transmission company's network customers.
- If a rate smoothing option is adopted, assure that similar safeguards to those adopted in Alberta's Rider I be provided so that industrial and resource customers cannot strand transmission and connection costs.

3 Distribution Network Planning

We have discussed regional planning issues for the interface between transmission and distribution above. Here we offer comments on electric distribution system planning.

3.1 Introduction

Northwatch submits that the performance based ratemaking (PBR) or formula-based ratemaking (FBR) framework works well for utilities when an industry is in a phase of declining costs, because it allows utility shareholders to retain profits under a rate cap of "inflation minus X". PBR works far less well for shareholders in an environment of increasing costs, for whatever the reason, because growing capital spending, which increases rate base, is not easy to capture in a system where costs or rates are set based on a formula, particularly one that includes productivity.

With pressure on distribution rates from system replacements, "smart grid", and new customer connections, distribution utilities and the OEB need to be careful when spending ratepayer money.[9]

As part of this process, there seems to be a building consensus that distributors should submit some type of capital plan that would be factored into the development of their rates.[10]

Northwatch is encouraged by the general idea, but must inject a series of cautionary notes, because the definition of how to do capital planning is too narrow in some ways, and has significant cost pitfalls, particularly in the "fun" areas of new technology – Information Technology (IT) and Smart Grid.

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[9] As the notes to the Executive Roundtable with Consumers reminds us (on page 3), capital spending is not only about rate increases. Consumers encouraged the Board to "change the lens through which capital investment is viewed – should be considering what utilities need to do to make the system reliable and efficient, but without a rate increase, rather than focusing on rate increases."

[10] See: OEB Strawman Model, reproduced in Electric Distributors Association (EDA) Stakeholder Conference Presentation, page 15; presentations of EDA (Ibid at page 16), and the Distribution Regulation Review Task Force (DRRTF, a group of large distributors and transmitters and gas companies) pages 4-8; Ontario Sustainable Energy Association, pages 3-7; and the executive Roundtable Notes with Distributors and Consumers.

3.2 Capital Planning for Distribution Facilities to Meet Load Growth

As noted in Northwatch's submission regarding regional planning, significant regional planning efforts are required to determine needs for new capacity and new customer hook-ups. We appreciate the Board's attempts to bring the results of land-use planning to the table when making these decisions. For example, Northwatch submits that adjacent distributors (including Hydro One in rural areas) work together to assure that both are not counting the same jobs or houses.

As noted in Northwatch's submission regarding regional planning, a capital planning process must be fluid and iterative. The utility shouldn't just submit a five year plan and build it out regardless of what happens in the real world. Nor should revenue requirements or rates be left constant in the event that major economic and demographic changes cause capital plans to become obsolete (e.g., the Great Recession).[11]

Northwatch would suggest that forecasts be provided every three years for an eight year period, with the forecasts for years 6-8 prepared in less detail than the nearer term forecasts. This recommendation is the same as Northwatch's position on Regional Planning and forecasting. The indicative information would be expected to be less accurate, but would allow a near-term plan to be changed if needed. For example, the indicative forecast might suggest oversizing a line to be built in year 3 for expected further load increases in year 7, rather than undertaking two separate projects that end up being more expensive, or might suggest a change in the optimal routing of feeder lines from a substation. Requesting a forecast every five years for a period of only five years also yields the potential for inaccuracy or for the need to build projects unforeseen in the last forecast period very quickly and without clear regulatory oversight.

[11] In California, where utilities present five year construction plans, the utilities and intervenors have been having arguments worth hundreds of millions of dollars of capital spending about recession-related reductions in customer hook-ups and capacity needs. The regulator has not made a decision on any of these cases yet, but some utilities are even making extreme claims that it is not only inappropriate but illegitimate to reduce their forecasts for information developed later than 2009 about economic and demographic factors affecting 2010-2015. The OEB should assure that it does not get into a position where forecasts are locked in in the face of contrary information.

As with regional planning, Northwatch disappointed that the OEB has removed energy efficiency and demand response from the scope of this proceeding[12], as they have a significant role to play in both regional planning of transmission and connection assets and in local distribution planning. We again refer to the stakeholder presentations of Pollution Probe and the Ontario Sustainable Energy Association, which both support inclusion of energy efficiency and demand response as key resources in the planning process that can reduce not only generation but also transmission and distribution costs. As noted in our regional planning submission, there may be a need for technical assistance to distributors to achieve targeted savings from energy efficiency and demand response.

3.3 Capital Planning for Replacement of Aging Facilities

The replacement of aging facilities installed from the Second World War to 1970 (and later for some early underground lines that do not meet current technological standards) is one of the areas driving costs up.

Northwatch has two general observations. First, there is the potential to spend O&M dollars now to avoid many more capital dollars later in some areas, and those O&M expenses should be encouraged. One area where some of the greatest potential for deferral of costs is present relates to wood poles, where inspection and treatment, including through-boring, can extend the life of poles for decades. While fairly long inspection intervals may be possible once poles are initially inspected and treated, the deferral of initial pole inspections is penny-wise and pound-foolish.

Second, the OEB will have to work with distributors and other interested parties in the planning process to balance the need for capital replacements, the prioritization of replacements (so that areas with poor reliability may be targeted first), and the need for other capital spending. Just because a utility plans an accelerated program does not mean

[12] Board Staff suggest at page 3 of the Board Staff paper on Regional Planning that this consultation (as per the Board's letter dated April 1, 2011) is not intended to be a broad integrated planning exercise that addresses solutions such as conservation and distributed generation as potential alternatives to infrastructure. Northwatch submits that an integrated planning process that considers conservation and demand response is essential and should be a key consideration of the Board in amending the TSC and renewing the electricity framework in Ontario.

that acceleration is always the right answer. A slower program of replacements focused first on areas where reliability can be improved that do not create as much rate pressure might be preferable.

3.4 Reducing Distribution Losses

The reduction of losses has both economic and environmental benefits. Spending capital and changing operational practices where cost-effective to reduce line losses and control voltage to reduce energy requirements should be part of any distribution system plan. Northwatch's submission regarding Measuring Distribution System Performance below reviews these issues in more detail. The failure to consider losses and voltage control as an aspect of distribution system performance essentially makes both planning and measurement of performance incomplete and results in an unreasonable and uneconomic increase in energy use.

3.5 Planning for Information Technology (IT) Projects

The DRRTF group provided an analysis of different types of capital projects and pointed specifically at "General Plant – Shorter Term Capital" as a cost category with high depreciation rates and a large impact on rates.[13] In addition, the high depreciation rates suggest that IT projects once done, must be constantly "refreshed" every few years, creating a rate treadmill trying to keep up with IT. In the real world, vendor support of certain software often ceases while a utility is still using the software without problems, causing utilities to continually upgrade.

Smart Grid projects are similar to IT projects. Smart Grid projects can also end up with relatively short lives (i.e., electromechanical meters have a life in excess of 30 years, while "smart" meters have a 15-20 year life due to the solid state technology). There are also issues of technical obsolescence for entities that get out front and start working on the cutting edge. Northwatch discusses Smart Grid issues later in response to Board Staff's Smart Grid Paper.

[13] DRRTF Stakeholder Presentation (March 2012), page 6.

As a matter of experience with other utilities, Northwatch's expert, Mr. William Marcus, has developed information that demonstrates that it is critical for regulators to keep their eyes on the ball and develop incentives to reduce the proliferation of IT software and hardware projects that must be refreshed and rewritten every few years. If a utility is facing serious challenges to keep up with growth, replace aging infrastructure, and install beneficial Smart Grid projects, IT should end up being carefully monitored. In private industry, IT is overhead, not a source of rate base and income, as it would be to an investor-owned utility. Therefore the private industry approach is to use as much off-the-shelf material as possible and to try to pay for software through productivity.[14] By comparison, a utility has different incentives, as it earns a return on capitalized software and recovers operating expenses as part of its cost structure. While it may be difficult to bring the entire price discipline of private industry into utility regulation in this area, the Board should recognize that it needs to exercise more oversight over IT spending in order to keep costs and rates under control to the extent possible while meeting other distribution spending priorities.

Northwatch therefore submits that the OEB should consider six means of maintaining cost discipline on IT spending in the capital planning process and the rate setting process:

1. Utilities should be required to provide business cases showing not only why each individual IT capital spending program above a certain size is reasonable but any estimates of dollar savings that could result from IT programs.

2. Utilities should prioritize IT expenditures to reflect capital constraints. Ratepayers cannot afford all the spending that might be "nice to have" but doesn't produce real benefits, particularly with rate pressure from other sources. It is not enough to claim that every IT dollar is equally necessary.

[14] See for example a case study of Bechtel in Network World, where Bechtel attempts to pay for new software out of savings in refreshing and maintenance. "Bechtel's new benchmarks": http://www.networkworld.com/news/2008/102808-bechtels-new.html; and "Building for the future, How do you create a more agile, responsive and cost-effective IT department?": http://www.networkworld.com/news/2008/102908-bechtel-future.html?page=2 . This information was presented in Southern California Edison's last General Rate Case by The Utility Reform Network, an intervenor. Prepared Testiony of Gayatri M. Schilberg on behalf of TURN, June, 2011, pages 14-16.

3. Off-the-shelf technologies should be preferred relative to items that the utility has to invent, write software for, or spend significant effort customizing. The skill set of a distribution or transmission utility does not generally overlap with that of an entrepreneurial computer software engineering company. When a utility tries to become its own software company, cost overruns are likely.

4. The planning process should encourage smaller and medium-sized distribution utilities to combine forces to purchase IT products and services and to share staffing. Diseconomies of scale become worse when every utility has to become an expert in IT in order to procure, operate, and maintain IT systems separately.

5. Northwatch submits that utilities should be held responsible for cost overruns on IT projects above forecasted costs including reasonable contingencies. Overruns should be partly or totally disallowed in any form of future rebasing from forecast to actual costs.

6. Finally, the Board should consider potential ratemaking mechanisms to require that new software pay for itself over its lifecycle (unless it has some other critical rationale like cybersecurity).[15]

[15] This concept could encompass the cost overrun issue discussed in the previous point in a single mechanism, but if this type of mechanism not adopted, the responsibility for cost overruns should still remain with the utility.

4 Defining and Measuring Performance of Electricity Transmitters and Distributors

Northwatch submits that Board Staff's paper regarding Defining and Measuring Performance of Transmitters and Distributors should have included the need to reduce energy used on the distribution system (by reducing distribution line losses and controlling customer voltage). Northwatch submits that this issue has both a cost dimension and a significant environmental dimension that the Board should consider when setting new or refining existing performance standards for transmitters and distributors.

4.1 Overview of Technology to Reduce Distribution Line Losses and Provide for Conservation Voltage Regulation

Northwatch submits that the typical performance based ratemaking mechanism rewards efficiency and cost cutting in the use of capital. In a vertically integrated utility, the utility would (at least in theory, though we have seen many examples in practice that did not work)[16] take the value of reduced losses (in reduced fuel use and reduced future generation requirements) into account in many routine business decisions. These include (1) purchasing both line transformers and substation transformers, sizing power lines for a given voltage, deciding on primary distribution service voltage levels, installing capacitors, improving system power factor, encouraging distributed generation that reduces losses in many cases, configuring the feeder network from a given substation, and determining the location of new substations and feeders as load growth occurs.

In general, losses are avoided by spending more money on capital, as larger wires and heavier transformers with more copper are associated with lower levels of losses. Many utilities have life-cycle costing methods of comparing the cost of different transformers using the first capital cost and the present value of losses, though many utilities still undervalue losses.[17]

[16] See the references on transformer capacity below.

[17] For example, Southwestern Public Service in Texas based its 2008 transformer efficiency evaluation on an energy cost of 2.806 cents per kWh and a capacity value of $36.51 per kW. See William B. Marcus, Direct Testimony on behalf of the Texas Office of Public Utility Counsel, Public Utility Commission of Texas

Some loss reduction costs may be more operational, such as switching between feeders and levelizing the load across feeders.

Finally, although most of these methods for reducing losses are well known, some of these methods for reducing losses fall under the "smart grid" concept such as integrated volt-var controls and automated load balancing across feeders.

A second form of energy reduction on the distribution system involves voltage control at the customer level. Because watts are volts multiplied by amperes or current (with an adjustment for power factor beyond the scope of this discussion), reducing the voltage to customers can reduce the amount of electricity used by customers. Methods have been used for 30 years in California (called Conservation Voltage Regulation or CVR) set the secondary voltage tolerance from 120 volts to 114 volts (instead of 126 to 114) in many locations where such reductions are feasible on the utility systems.[18] Recently, several distribution utilities in the Pacific Northwest have adopted CVR.[19]

CVR reduces sales to customers. Not only are customer bills reduced, but the life of lightbulbs and appliances is enhanced. The fact that sales to customers and customer bills are reduced is one reason why utilities have traditionally been reluctant to pursue this form of conservation. CVR also requires capital spending on some circuits, though the cost per kWh of conserved energy is relatively low.

Docket No. 35763, (October 2008), pages 58-59 found at: http://interchange.puc.state.tx.us/WebApp/Interchange/application/dbapps/filings/pgSearch_Results.asp?TXT_CNTR_NO=35763&TXT_ITEM_NO=606.
In an even worse example from two decades ago, a Yukon distribution utility purchased transformers that were cost-effective with a very low avoided energy cost of 0.7 cents per kWh (cost of coal burned by its Alberta parent company in the early 1990s) while burning diesel fuel that cost about 8 cents/kWh at the time. See William B. Marcus, Report Regarding the Capital Budgets of the Yukon Energy Corporation and the Yukon Electrical Company, Limited. (October, 1992), pp. 23-24 and Appendix C.

[18] Pacific Gas and Electric Company, Rule 2, Sheet 4. Class A circuits have a maximum voltage of 120 volts. http://www.pge.com/tariffs/tm2/pdf/ELEC_RULES_2.pdf

[19] Robert Fletcher, Snohomish Public Utility District, "Conservation Voltage Regulation (CVR)", Presentation to Bonneville Power Administration Utility Energy Efficiency Summit, March, 2009. http://www.bpa.gov/Energy/N/utilities_sharing_ee/Utility_Summit/Workshop2009/pdf/BobFletcherSnohomishPUD.pdf

A more modern program of dispatchable CVR (particularly during critical peak periods) may fall under a smart grid rubric.[20]

4.2 Current Utility Incentives Do Not Support Distribution Loss Reduction

Northwatch submits that in traditional vertically integrated utilities, distribution loss reduction (but not CVR) could be theoretically captured. Reduced losses would reduce generation costs, which would be internalized by the utility, although with fuel adjustment clauses, the incentive would be reduced.

Northwatch submits that Ontario's distribution system, which is not vertically integrated, lacks incentives for efficiency. –Power generators make money from generating more power; they gain financially from distribution line losses.[21] Power retailers are generally given some combination of fixed line loss factors and a share of the system's "lost and unaccounted for" power (theft, losses not measured properly, errors in load profiling before the installation of "smart meters", etc.). Accordingly, power retailers are largely indifferent to losses and may even gain if they have a (regulated or unregulated) margin when they sell more power. The distribution utility generally does not see the consequences of changes in losses in its decisions, except as a retailer. It therefore has incentives to ignore losses and reduce capital costs.

Northwatch submits that a movement toward formula-based ratemaking or performance-based ratemaking may further incent losses. A formula-based mechanism tends to promote reductions in total system costs measured by the mechanism. Trade-offs between capital spending and operating expense can be accommodated in the mechanism but there is no incentive to spend extra money on capital to obtain a reduction in line

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[20] "Tantalus Completes Deployment of New Dispatchable Conservation Voltage Regulation Program" *Smart Grid News,* March 13, 2012. http://www.smartgridnews.com/artman/publish/Delivery_Grid_Optimization/Shouldn-t-every-utility-use-voltage-optimization-right-now-4571-page2.html

[21] Unlike distribution losses, the location of generators has a significant impact on transmission losses. Depending on the regulatory regime, transmission losses are easier to charge to generators, through locational marginal prices or similar mechanisms. Therefore, generators are not necessarily indifferent to transmission losses. However, the transmission utility is in the same position as the distributor if it can simply charge losses to generators without making economic decisions to reduce losses.

losses that accrues to other parties, and even less of an incentive to reduce sales for customer voltage control, which simply reduces the distributor's profit.

In a recent formula-based ratemaking case in Alberta involving Enmax Power Corp., which serves the City of Calgary, the Utilities Consumer Advocate identified the problem that losses were not being considered. Ultimately a loss mechanism was added to that program, which allowed Enmax to spend money on capital projects to reduce losses and recover the costs to the extent that there were actual loss reductions over a ten-year period.[22] While this may not be enough (because the payback period may be too short and because costs that are not fully monetized like Greenhouse Gas reduction are not included), it was at least a start.

4.3 Recommendations on Loss Reduction Measurement and Planning

Because the mechanism for measuring and addressing losses was largely missed by PEG, in its report dated April 2011, and by Board Staff, Northwatch offers some constructive suggestions, but believes a group effort could produce a more robust result.

Northwatch's recommendations support a fast-track process to assure that the purchasing of transformers takes energy losses into account. Buying inefficient transformers creates a lost opportunity in energy efficiency. If the efficient transformers are not purchased, they will not be replaced for decades, because it will not be cost-effective to scrap them just to gain more efficiency. Remaining issues related to loss evaluation and Conservation Voltage Regulation are proposed for a more deliberative stakeholder review.

Northwatch therefore provides the following recommendations regarding line losses:

1. The OEB should establish a requirement that distributors consider life-cycle costs including the value of losses (energy, capacity, and greenhouse gases) when bidding for line transformers and substation transformers.

[22] Alberta Utilities Commission (AUC) Decision 2009-226 (on settlement regarding Enmax losses). See also the original AUC Decision 2009-035.

2. The OEB should, after consultation with stakeholders, expeditiously develop current estimates of the lifecycle values of energy and capacity that would be required to be used in loss evaluation of transformers and other distribution equipment and should develop a process to periodically update those estimates.

3. The OEB should establish a stakeholder process to evaluate changes to ratemaking specifically to include line loss reduction as a performance element in both capital planning and ratemaking. Among other potential mechanisms, the OEB should consider: (1) the Alberta proposal for allowing recovery in rates of capital projects that pay for themselves through loss reduction; (2) establishing fixed loss percentages; or (3) providing some additional money for fixed capital expenditures that reduce losses if other capital-related money is to be provided to distributors.[23]

4. The OEB should establish a stakeholder process to evaluate conservation voltage regulation in Ontario, with reasonable one-time adjustments to ratemaking for lost sales if adopted. As part of that process the OEB should initially require that distributors (over a certain size) identify circuits that could be held at a maximum of 120 volts without degrading voltage at the present time and identify circuits that could be held to 120 volts with relatively small amounts of capital investment.

[23] See, for example submission of DRRTF to OEB on Renewed Regulatory Framework Review; these electric and gas distributors support a different mechanism for allowing increases in spending for capital projects between rate rebasing periods. While Northwatch is not commenting on the substance of DRRTF's entire proposal, within reason treating extra capital costs for loss reduction as an exception to an "inflation minus X" ratemaking strategy would make sense to Northwatch.

5 Establishment, Implementation and Promotion of a Smart Grid in Ontario

5.1 Smart Grid Planning Principles

Northwatch offers some comments on the Smart Grid Planning process, particularly as it is integrated with overall distribution planning.

While Northwatch supports "Smart Grid" projects when they have environmental or economic benefits, "Smart Grid" can become too much of a buzzword for anything technical that a utility wants to do to its distribution system, regardless of cost-effectiveness. A similar set of issues arises for Smart Grid projects as for IT projects. Again, significant cost consciousness is needed in the planning process. Northwatch offers some observations.

The California Public Utilities Commission has made cost-effectiveness and least-cost analysis critical priorities when analyzing new smart grid projects. Its decision 10-06-047 in its Smart Grid Rulemaking (R.08-12-009) recognized that modernizing the transmission and distribution system would require consideration of costs and benefits of such modernization. To that end the Commission included "cost estimates" and "benefits estimates" in the list of topics that a utility would need to address in its Smart Grid Deployment Plan.[24] The decision also included very specific and clear directives regarding the cost-effectiveness and the cost-benefit of utility Smart Grid programs:

> In those cases, where the investment in a Smart Grid is necessary to achieve a policy requirement, ***then a least-cost analysis may be appropriate***. However, in cases where the Smart Grid investment will produce benefits beyond simple compliance with a regulatory requirement, we believe ***a cost-benefit analysis is appropriate***.[25]

The decision also addressed the need to identify and estimate benefits that might prove hard to quantify:

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[24] D.10-06-047, Sections 3.8.2 and 3.9.2, pp. 60-61. Also, p. 144 (Ordering Paragraphs. 12 and 13), emphasis added.
[25] Ibid., Sec. 3.9.2, p. 74.

> In addition to facilitating the achievement of other policy goals, Smart Grid investments could produce other benefits that are difficult to quantify, but potentially significant, such as achievement of environmental goals. Smart Grid investments could both improve the overall reliability of the electric grid and enable the development of work procedures that improve worker safety. In particular, knowing quickly whether a section of the grid is energized could enable the development of additional procedures to protect workers. ***The benefit section of the Smart Grid Deployment Plan should attempt to quantify these benefits***. Furthermore, Smart Grid investment could also produce ***quantifiable environmental and economic benefits. The benefits estimates in the deployment plans should identify and estimate such benefits***.[26]

Northwatch submits that the OEB should follow this general lead in the Smart Grid planning process. The OEB needs to recognize that many "Smart Grid" projects are likely to have a positive benefit, but are still in the" basic research" stage. Therefore many projects will never be cost-effective. Automation is not always the right answer everywhere. Utilities must be required to submit business cases (and indicative business cases for pilot programs – based on costs if the pilot is successful) to weed out waste and cut programs that are not cost-effective. These cases should include both estimates of hard dollar savings with supporting documentation and estimates of reliability improvements (if applicable).[27] While some might consider the inclusion of cost-effectiveness in a pilot project to be problematic, Northwatch is not suggesting that the Board require hard estimates – just reasonable cost and benefit estimates if the pilot is successful so that projects that produce little benefits, whether economic or environmental, under favorable conditions can be weeded out before money is wasted.

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[26] Ibid., p. 75, emphasis added.

[27] For example, Southern California Edison asked for a program, that if implemented on its entire system would cost $60 million to improve its ability to keep track of the condition of substation transformers. Edison spends $60,000 per year to do that job manually now, and could achieve 90% of the benefits of the automated program by spending another $60,000 to $120,000 per year on additional manual inspections. Garrick Jones, Prepared Testimony in Southern California Edison's 2012 Test Year General Rate Case on behalf of The Utility Reform Network. California Public Utilities Commission Application 10-11-015, pages 45-52.

Another key concern of Northwatch is obsolescence. Utilities and the Board should consider the possibility—indeed likelihood—that Smart equipment will reach the end of its useful life at a speed that makes the entire stream of services provided by the equipment less attractive. Therefore, the planning process needs to scrutinize utilities' useful life assumptions when reviewing any cost-benefit or cost–effectiveness studies, or any other type of analysis that a utility uses to support a proposed Smart Grid project. Utilities should be asked to support all of their useful life assumptions, and discuss the potential for equipment obsolescence, whether it be because of equipment parts or the loss of vendor technical assistance. The utility should provide sensitivity analyses showing the impact of different useful life assumptions on a cost-benefit or cost–effectiveness basis. Such analyses should include environmental impacts of short-life electronic equipment, namely, analysis of both resource-use and end-of-life disposal and management of such equipment.

Finally, planners and economists must realize that a typical cost-effectiveness analysis presents two choices. "Do nothing" versus "do the project now." For Smart Grid projects, there is often a third type of choice. Defer the project and do it later, or slowdown implementation after a pilot is done. In areas where technology is in an unsettled state and likely to change, there are occasions when the early bird does not get the worm. Instead the early adopter gets a high cost system or one without features that would have been available had the utility waited. Obsolescence can also be tied into early adoption. An early system that is superseded by better technology is the type that could easily lose technical support before the physical life of the system is over.

Ontario-specific conditions and the need for cost-effectiveness lead Northwatch to two additional conclusions in Smart Grid planning.

1. As with IT, off-the-shelf is likely to be better for most Smart Grid projects, particularly for smaller and medium-sized distributors. We do not believe it reasonable for utilities to plan to invent new technologies or highly customize applications for use. These are again likely to be recipes for cost overruns and poor performance.

2. With a fragmented distribution system like Ontario, everyone does not have to run pilot projects of the same programs. For example, volt-var optimization has significant benefits in reducing losses and reducing the need for distribution capacity investments, but every distributor may not need to kick the tires on a pilot program before gearing up. Coordination among distributors in the same region or with similar characteristics to divide up pilot programs is an important planning element to prevent waste and reduce risk of poor outcomes.

In sum, the Board should place cost-effectiveness as a paramount consideration when analyzing smart grid projects, should act carefully where cost-effectiveness cannot be readily established, should be cautious about early adoption of technology, should favor off-the-shelf applications, and should recognize that not all distributors need to undertake pilot projects for the same technology.

6 Conclusion

Northwatch appreciates the opportunity to present this submission and to work with the Board in this process. Northwatch believes that the regional planning process should be broader and include issues of power supply and demand. Under the narrower framework presented by the Board, Northwatch has offered suggestions to improve both the regional planning process and individual distributors' planning by:

1. Supporting the Board Staff's proposal to incorporate land use information from both provincial (Crown land) and municipal governments;
2. Providing for a longer planning horizon (8 years) than an action horizon (5 years) to identify key trends;
3. Including energy efficiency, demand response and distributed generation in planning for new wires while providing technical assistance to distributors to assure that these resources are actually developed regionally when needed to defer wires projects,
4. Including distribution system energy efficiency (better transformers and wires, and Conservation Voltage Regulation, among other methods) in the development of utility capital and operating plans; and
5. Assuring that IT and Smart Grid investments are solidly grounded in cost-effectiveness so that money is not wasted on these high cost items that have short depreciable lives and that generate a "need" for ongoing spending to "refresh" technology.

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