Regulating Electric Utilities – Discussion Paper

Phase One Governance Study — Liberalization and Performance-Based Regulation

NOVA SCOTIA

Contents

1.0 Background

1.1 A Review of our Electricity System

In the fall of 2013, the Government of Nova Scotia announced a comprehensive review of the province's electricity system. The commitment to a review was put into legislation as part of the Electricity Reform Act. The review focuses on three areas:

- emerging technologies that could change how we generate, store, and use electricity (technology study)
- how much electricity we need and where we will get it from (market trends study)
- how we should organize the ownership and oversight of electricity suppliers in the province, especially the major supplier – Nova Scotia Power Inc. (governance study)

Expert technical studies on these topics were developed as part of the first phase of the Electricity System Review. The purpose of these studies is to help the Department of Energy and the general public better understand the challenges, opportunities, and possible solutions for the province's electricity marketplace over the next 10 to 30 years.

The technical studies relating to market trends and emerging technologies, released in June, will be further refined as more information becomes available. At the request of the Utility and Review Board, Nova Scotia Power Inc. is currently leading a separate but related process to examine future needs and options for supply of electricity, using a variety of planning scenarios. The results of this Integrated Resource Planning (IRP) process will be used to update the reports released on www.novascotia.ca/electricityfuture.

Background research has also been released on how other provinces and states deal with the oversight and delivery of electricity, including

- a literature review of success factors in, and barriers to, bringing various kinds of electricity competition to markets, with case studies showing lessons learned from other jurisdictions
- an overview of Nova Scotia's current situation

These studies, combined with the two previously released studies, form some of the background for public consultation on Nova Scotia's electricity future, which will take place in the fall of 2014.

This document summarizes the findings of background reports relating to the governance study component of the review. The intent of this document is to help shape the questions that the final governance study raises about how we should apply this knowledge in the Nova Scotia context.

1.2 Nova Scotia's Electricity System: Overview

Nova Scotia Power Inc. (NSPI) supplies most of the electricity in Nova Scotia and owns more than 95 per cent of the province's electricity systems. It is a vertically integrated utility, which means that it generates, transmits, and distributes electricity. NSPI serves about 500,000 residential, commercial, and industrial customers.

The consolidation of smaller electrical utilities into a Crown corporation occurred for a number of reasons, including the difficult financial positions of some of the smaller utilities. The consolidation created economies of scale, which, it was hoped, would lower the average cost for service across the province. As such, it was designed to be a monopoly, with oversight given to the Utility and Review Board (UARB).

In 1992, partially in response to increasing electricity prices and liabilities, the Nova Scotia Power Corporation was privatized by the government of the day. The current corporation (NSPI) is governed by legislation that requires its head office to be in Nova Scotia and requires that the majority of shareholders be Canadian.

NSPI can currently generate as much as 2,700 MW (owned or contracted from independent power producers). The province has only one limited transmission connection to another energy market: a link to New Brunswick that allows exports from Nova Scotia but is not always available for importing energy.

Because many provinces in Canada have vast hydroelectric resources and power plants built decades ago, Canada as a whole has some of the least expensive electricity prices anywhere. Since Nova Scotia does not have large hydro resources, or the existing infrastructure to access them, we have higher electricity prices than many other provinces. Still, our prices are lower than many other places in North America and Europe.

The London Economics International (LEI) Working Paper indicates that Nova Scotia prices are not out of line with similar-sized markets.[1] However, this does not take away from business and residential customers who have faced rapidly escalating prices in recent years (the majority of which are related to fuel costs) and prices that are currently among the highest in Canada.

As a near monopoly, Nova Scotia Power has responsibilities imposed under law. One of them is an obligation to serve – the company must provide electricity to customers who request it, anywhere in Nova Scotia. This is a cost pressure that does not exist in some other markets. In deregulated or totally open markets, power companies can choose to provide service only when it makes economic sense to do so.

Nova Scotia's power sector is open for competition in some sectors. A process of opening parts of the market (gradual market liberalization) began with the province's 2001 Energy Strategy. Municipal utilities, which had not been rolled into NSPI and continued to operate independently, have not been required to buy their electricity from NSPI since the Electricity Act and the Wholesale Market Rules Regulations were proclaimed in 2007. This small opening of the "wholesale" market was intended to be the beginning of further openings, but liberalization stalled because of fears that there would not be enough competition.

Since 2007, worldwide energy production opportunities around renewables have enabled smaller market entries with capital costs lower than those of the large thermal plants of the past. With the passage of the Electricity Reform Act in the fall of 2013, the next step in market opening is now taking place. The legislation will allow producers of low-impact renewable electricity (independent wind or solar electricity producers, for example) to sell directly to residential, institutional, or business customers. The rules for such sales are under development now, with the consultation and approval process expected to be complete in late 2015 or early 2016.

Independent power producers (IPPs) also have open access to the transmission system. That means they are able to transmit power to their customers through NSPI transmission lines by paying open-access transmission tariffs (OATT). The costs of maintaining the transmission system are embedded in the rates customers currently pay. OATT fees simply ensure that users of the system who are not utility customers continue to pay their share.

[1] *This report will be posted online at www.novascotia.ca/electricityfuture.*

NSPI is currently regulated under what is called a Cost of Service Model. Under this model, the rates charged by the utility must be based on the actual cost of providing electricity in Nova Scotia. That cost includes the cost of capital used to build the facilities – including interest on debt and a return to the shareholders who have invested. The investment by shareholders allows NSPI to borrow money at more-competitive interest rates. Interest on capital expenditures is ultimately paid by ratepayers.

All customers of a specific rate class share equitably in covering the resulting cost of providing the service to that class. This means that a residential customer in a rural area pays the same rate as one living close to a power plant. It also means that if the number of customers shrinks, the remaining customers have to cover the cost of the plants and related transmission and distribution facilities built to serve those customers. For the same reason, the loss of a large customer using a great deal of electricity can have consequences for the rates of all customers. Likewise, if a capital asset such as a power plant closes before the end of its useful life, customers may continue paying for that asset even though it is not producing. All these measures balance the interests of customers and investors – and in a properly regulated system, the outcome should be a fair set of rates for all interests.

One of the key challenges facing the system in Nova Scotia is the potential for a loss of customers leading to declining load growth. As noted, the loss of a large industrial customer, and the consequent large load losses, would result in a significant drop in demand for electricity.[2] Efficiency and energy conservation measures by customers to save on their electricity bills also reduce demand for electricity, or they result in less growth than would otherwise be expected. Other factors – such as an increase in heat pumps, increased air conditioning loads, a significant and rapid growth in electric vehicle usage, or a significant increase in economic growth – could result in more demand for electricity. In short, the need for electricity could be larger or smaller than expected in the future, making planning difficult.

In recent years, Nova Scotians have been more vocal in seeking more accountability and transparency from NSPI on how the corporation spends dollars received from customers. The Electricity System Review looks, in part, at how our electricity system is managed and monitored (or governed). The review is examining the merits of other regulatory models used to monitor utility performance and to provide performance-based incentives and penalties.

[2] *For further discussion on the impacts of industrial customers on Nova Scotia's electricity demand, see Nova Scotia Electricity System Review: Summary Report – Emerging Technology and Market Trends Studies*

2.0 Market Models and Governance

2.1 Market Liberalization

While the term deregulation is sometimes used in relation to opening up electricity markets, the term liberalization (or introducing competition in varying degrees to our marketplace) more accurately describes Nova Scotia's historical path to change and our likely electricity future. Liberalization means more competition for the generation of electricity and potentially more choice in who will supply the electricity. This can also include introducing incentives and penalties for meeting, or failing to meet, performance standards.

Liberalization does not mean the elimination of regulation; rather, it is reshaping of regulatory regimes. It is therefore not the same as deregulation. Liberalization can include a wide range of options. Indeed, Nova Scotia's own Community Feed-in Tariff (COMFIT) program is part of the liberalization of the Nova Scotia marketplace, in that community-owned projects are providing generation options. Reshaping the regulatory regime could mean more focus on system output (performance-based rate making) instead of input (cost of service models), a concept that is explained in Section 3.0. It could also mean some combination of both models.

Experts have looked at experience elsewhere and have noted that before a market is opened up fully, there must be an expectation that a number of large-scale competitors with provincially widespread geographic access will be able to enter the market. Otherwise, we could face a handful of monopolies that are not as well regulated.

If the market does have competitors, a number of other factors come into play:

- The businesses that come to compete need consistent, long-term government policy and public support.
- If a decision is made to depend on the market, experience shows that it is best to let the market work out supply and demand imbalances. Government should not intervene by forcing price changes.
- Transmission investments must be made to enable a full range of local and distant, large and small competitors to enter the market.

LEI notes in the governance study that competitiveness in the generation sector is probably the single most important factor that will either lead to success or undermine restructuring efforts[3]. The LEI Working Paper states that market concentration (the number of players in the market) determines competitiveness,

[3] *London Economics International LLC, Literature review: regulatory economics and performance-based ratemaking*

including in the generation market. The presence of at least five players of similar size with the ability to supply power throughout the province would be sufficient to achieve a reasonably level playing field. However, markets can be opened in stages, or only partially, to address some of the concerns of smaller geographic areas or areas with fewer large competitors. This is an issue worth considering in Nova Scotia, especially where large thermal coal plants will phase out over time to meet federal requirements. As these phase-outs occur, there will be opportunities for new generation sources and new competition options.

Liberalization has implications for reliability. Today, NSPI (or the relevant municipal utility) can be held directly responsible for all issues related to maintaining safety and reliability standards. They are also obliged to serve any customer who requests service, as previously noted. Under the current system, there is no doubt who is responsible if the power goes out or there is not enough electricity to meet a growth in demand.

A fully liberalized system that depends on market decisions diffuses responsibility for these matters among many players looking after their own economic interests. Experience shows that in such a completely liberalized system, there is a need for an Integrated System Operator (ISO) or TransCo (transmission company) to ensure the coordination of services. The ISO may also have responsibility for planning coordination, or this may be delegated to another body. Nevertheless, such a marketplace is much more complicated, and no single entity has the ability to ensure that all customers continue to receive reliable service.

It is also important to note that full liberalization and increased competition does not guarantee decreased power rates. Indeed, no option for governing an electricity marketplace can guarantee that. Competition, if possible, better mitigates price increases over the longer term, not the short term. Competition can, however, provide natural pressure to ensure cost effectiveness and efficiency, which can mitigate or slow cost increases. Experience shows that in many cases of full liberalization or deregulation, particularly in the beginning, customers have seen sharp increases in their electricity costs, as new players have new costs and the existing player maintains historic costs. It is likely, however, that over time electricity costs will always be linked to some degree with inflation.

2.2 Forms of Regulation

Three forms of regulation are explored in the governance study.

- traditional regulation (cost of service approach, which includes a cap on, or a band[4] for, the rate of return allowed for capital invested by the utility)
- performance-based regulation (e.g., benefit sharing, quality targets)
- light-handed regulation (e.g., price caps, regulatory holidays)

Currently, utility rates in Nova Scotia are set through the cost of service (COS) approach. The COS model can provide a clear foundation for investors to fund necessary infrastructure, is a relatively understandable and transparent process, and is consistent with historical practices. However, this pure model is becoming less common. Many Nova Scotians have raised concerns about the cost of electricity, and a perception exists that ratepayers may not be getting full value for the money they pay.

The COS approach is supposed to balance the needs of utility investors and customers in circumstances where full competition is unlikely. It involves determining the total cost to deliver electricity (including system operating costs) by adding a pre-determined rate of return to the total reasonable expenses incurred by the utility in providing electricity to its customers. In Nova Scotia, that rate of return is based on the total capital assets of the utility and is not related to the amount of electricity produced or sold.

Costs are shared among all ratepayers based on their rate classes (e.g., residential, commercial, industrial). When the utility's overall expenses rise, it will request a rate increase, which will require a public rate hearing. COS models work well where utilities are looking to significantly expand infrastructure.

It is suggested that a broad performance-based regulation (PBR) approach, once properly established, may reduce the number, length, cost, and complexity of regulatory hearings, and that there could be stronger incentives for the utility to minimize costs and rate increases. It should be noted that ratepayers foot the cost of the regulatory process. A reduction or streamlining of the regulatory burden, while still ensuring appropriate and sufficient regulatory oversight, would lead to cost savings, which would be passed on to ratepayers.

While the UARB process has been revised and refined in the decades since the

[4] *A margin set around what can be earned by the utility*

privatization of NSPI, incentives under the COS approach do not necessarily work properly within a market that is already becoming more competitive. For example:

• It is difficult to compare a bid from a COS utility, where risk is shared with ratepayers, with a bid from an independent power producer, where risk is fully factored in the bid.

• Under COS, the utility would favour its own capital investments for services so it can earn a rate of return on such investments rather than seeing others provide the same service.

• The utility has no inherent economic rationale for reducing costs.

• The utility has no economic incentive to meet possible performance targets (such as reliability, rate impact, and so forth), as they are not directly related to its shareholder return.

Each of these gaps is intended to be covered through regulation and oversight by the UARB and the relevant international and national codes and standards. However, many stakeholders are becoming more skeptical about whether the model is delivering what they want or expect. The public is becoming more concerned about a process that is structured simply to cover costs rather than to encourage savings and performance.

Performance-based regulation is seen as a possible alternative to achieve the following customer objectives: quality of service, optimal capital spending, competitive rates, avoidance of discrimination, and information disclosure.

It should also be explained that currently the Fuel Adjustment Mechanism (FAM), which is regulated by the UARB, ensures that power rates reflect the actual cost of fuel and not just what was forecast by NSPI. At the end of each year, through a UARB process, rates are adjusted and could go up or down depending on the true cost of fuel. Fuel has been a significant source of cost pressure for Nova Scotia, especially as coal prices have risen and natural gas prices have witnessed extraordinarily high winter peaks.

3.0 Performance-based Regulation

Performance-based regulation (PBR) depends on outcomes rather than methods. Rather than requiring specific behaviours, the regulator sets goals and the utilities determine how to achieve them.

> **"It is a delicate balance: the regulator must allow enough discretion for independently driven change and innovation to take place, but not so much that it leads to unintended negative consequences."[5]**

Performance-based regulation should be viewed as a spectrum. Through a stakeholder engagement process, selected tools and objectives create the PBR regime. They can be relatively straightforward, such as incentives and penalties, or they may be complicated and account for a variety of complex factors. In its simplest form, PBR sets service standards and applies incentives and/or penalties for success or failure in achieving these standards. This is much like a school report card in which ratepayers are involved at the beginning to determine what the utility is scored on.

This system works best when addressing matters that are largely within the control of the utility and when there are clear paths to reaching compliance from good management attention and execution. Examples would include benchmarking for avoiding power outages, and for return of service when an outage occurs. The complexity comes with determining which events would be reasonably within the utility's control, and the relative weighting to give to each issue.

In a more complex form, PBR covers the entire spectrum and goes to the heart of calculating utility rates using a formula that adjusts utility rate changes to inflation minus an enhanced efficiency or industry productivity factor. Except in limited circumstances, rates cannot rise above inflation in such a model. This benefits ratepayers, especially commercial and industrial ratepayers, who can plan ahead for the maximum rate impact their operations are likely to see.

A full PBR framework could replace the current cost-of-service (or rate-base rate of return) regulatory system. A decision about the Fuel Adjustment Mechanism would be required: whether it would be dealt with outside the PBR framework or as a hybrid of some kind.

[5] *C.R. Carlson, Performance Based Regulation of Utilities: Theoretical Developments in the Last Two Decades, The Van Horne Institute, March 2010.*

Full PBR can include many different approaches, ranging from price caps (capping the cost that can be recovered so that rate growth is limited) and revenue caps (capping how much can be earned, which also limits rate growth) to performance measured against benchmarks (usually developed from industry data).

Others approaches include:

- rate freezes[6] and rate case moratoriums[7]
- benchmarking/yardsticks
- mechanisms to share costs and earnings
- targeted incentives for:
    - procurement costs (fuel, purchased power)
    - plant operations (power plant availability and efficiency)
    - "external" system costs (line losses, congestion)
    - non-cost goals (reliability, service quality, end-use efficiency)

These mechanisms are usually determined through negotiations between customer representatives and the utility. There is no one-size-fits-all solution – a full PBR regime for Nova Scotia would have to be specific to Nova Scotia. The transition to performance-based regulation requires a substantial amount of planning and stakeholder engagement. The process of creating new performance metrics and rates would be a multi-year process and likely would not result in price decreases – just as the current COS model, or any regulatory model, should not be expected to result in decreases. However, a PBR model could provide predictability and accountability, which some stakeholders have indicated is missing in the current system.

3.1 Performance-based Regulation in Other Jurisdictions

Globally, many jurisdictions are moving from COS models to PBR. However, not all PBR experiences have been positive.

In particular, there are lessons to be learned from Ontario's recent experience with performance-based regulation. Productivity and technical and allocative efficiency have declined. Electricity rates have increased, while reliability has decreased.

[6] Holds rates so that there are no rate increases for a set amount of time
[7] Holds rates constant for a set amount of time; however, this relates more to inhibiting the utility from initiating/developing the case for increasing or decreasing rates

The United Kingdom has had comparative success in implementing performance-based regulations, but it seems to have been applied only to electricity distribution companies. A 2003 working paper found that incentive regulation alone (a form of PBR) was associated with an increase in the average duration of electricity outages[8]. Implementing explicit quality benchmarks, however, reduced the average duration of outages per customer. The study also found that incentive regulation reduced the utility's operational and maintenance expenses at the distribution level, which led to an increase in the duration of electric outages.

Lessons to be learned from these models indicate that keys to success include stakeholder engagement, clearly articulated objectives for model creation, and allowing the model, once established, to function independently of government decision-making processes.

3.2 Blended Models

Adoption of a performance-based system does not have to be all or nothing. There are situations where varying levels of a conventional COS approach and PBR have been used to form a hybrid approach.

The spectrum can range from pure cost of service (where the rate is equal to what it costs to provide electricity) to pure performance-based regulation with incentives such as those in competitive markets. The rate-of-return structure could account for the cost of delivering services and include performance benchmarks such as reliability. This would allow flexibility to accommodate both years when large-scale capital investment is required and years when the focus would be more on performance standards.

[8] *Anna Ter-Martirosyan, Effects of Incentive Regulation on Quality of Service in Electricity Markets, Working Paper, George Washington University, March 2003.*

Incentive Spectrum (Range of COS and PBR)

Pure COS	Rates equal to cost of service
Alberta COS	Annual rate cases, forward test-year with true-up
US COS	Rate cases every few years, historic or forward test-year without true-up, possibly add-on incentives for specific items
US rate case moratoriums	3- to 5-year rate freeze, historic or forward Test-year, possibly earnings sharing and add-on incentives
UK RPI-X	Rates and X-factor to recover a company forecast cost of service, reset both rates and X-factor every 5 years
Price caps for US/Canadian telecom, US oil pipelines	Company-specific starting point, industry-wide rate trends, (almost) no rebasing
Pure PBR	Incentives like those in competitive markets

Performance-based regulation mechanisms can also include service-quality penalties of no less than 1 per cent (100 basis points) of equity.

As noted earlier, performance benchmarks could be narrowly focused to target certain objectives or to be part of a broader system. Experience elsewhere suggests that such benchmarks should be set at the most recent three-year average performance. Such benchmarks should be established for a limited number of broad measures that are easily tracked and important to customers, including

- customer complaints
- outage duration
- frequency of outages lasting five minutes or longer
- frequency of momentary power outages
- storm outage response time
- hours lost due to accidents

4.0 Nova Scotia Context

The Phase One technical studies (market trends, emerging technologies, and governance) pose some interesting lessons learned for Nova Scotia in the face of possible declining load growth, increased unpredictability, and price volatility.

The governance study has been divided into two parts. The first part provides the basis for this summary. The second (currently underway) will build on lessons learned from previous studies and position them in the Nova Scotia context. Several questions will be asked in the second part of the governance study, including the following:

- Does Nova Scotia currently have the required conditions to make further market liberalization successful? What may happen to improve those conditions?

- What can be done to increase opportunities for competition?

- How could Nova Scotia Power Inc. be further regulated?

- What are the associated costs with transitioning to a new system, and do the benefits outweigh those costs?

- What would a PBR matrix look like for Nova Scotia?

The second part of the governance study will also look at the broader issue of longer-term potential regulatory and market reshaping in terms of costs and benefits to ratepayers. It will consider associated planning processes and overall benefits.

This information will be shared with Nova Scotians so they can develop informed opinions in order to fully engage in governance discussions.

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