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E-BRIEF

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PUBLIC INVESTMENTS AND INFRASTRUCTURE

Adding More Juice: How Private Investors can Improve the Performance of Provincial Power Assets

by
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- 69 percent of Canadian electricity generation and 61 percent of Canadians receive electricity from provincially owned electricity utilities. Forecasting future demand for electricity is difficult, and with a provincially owned utility the risk of poor forecasting is either borne by the taxpayer or the ratepayer – who are often the same person. This leads to higher electricity bills when government and regulators get those forecasts wrong.
- Involving private capital in this market has been done successfully in the US, UK, Australia and New Zealand. By involving private risk capital, provinces can transfer investment risk to private investors. If the market is better able to manage this demand risk than central government decisions – a view we take in most other sectors of the economy – then overall electricity prices for consumers will fall.
- These assets also represent significant investment of public dollars over many decades. But continued ownership is not necessary to achieve government objectives such as affordable prices for consumers. By involving private capital in the ownership of these assets, governments can redeploy this investment to other projects where the private sector is unwilling to invest – making our scarce dollars go further in achieving policy objectives. Three provinces currently have \$31-\$45 billion in equity invested in these utilities – and other provinces have significant investments as well, although they are not likely valuable to investors.

Seven provinces and all three territories own electricity utilities with significant responsibility for generating, transmitting and distributing power to their citizens. While governments have a public-policy need to ensure affordable, reliable electricity supply for their customers, continued public ownership is not necessary to achieve this objective.

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These utilities separate into three groups – (i) utilities on full user-fee cost recovery models with commercial structures ready for private capital, (ii) utilities where consumers are not charged the full cost of investing capital in the system, and (iii) small territorially owned utilities.

Three electricity utilities in three provinces – BC, Ontario and Quebec – have rate-setting models that charge consumers both the cost of producing power and the cost of investing capital in power generation and transmission assets. I estimate that provincial equity ownership in these three utilities is worth $31-45 billion that could be redeployed into other sectors. Ontario, in recent years, has sold a 50.1 percent stake in Hydro One[1] – the provider of electricity transmission throughout the province and distribution to end consumers in many areas.

In several provinces – New Brunswick, Manitoba and Newfoundland, and Saskatchewan, as well as in the case of Ontario Power Generation (OPG) – consumers do not pay the full cost of investing capital. As a result, attracting continued private investment would be undesirable without significant changes to the utility's economic model. We know this because a private investor would be unlikely to rebuild the same portfolio of assets, given their current profitability, if they had such an option.

Finally, all three territories have territorially owned electricity utilities. These operate at much smaller scale and face different challenges. A separate analysis of these systems would be required.

This E-Brief examines the eight largest electricity utilities in the first two categories: the provincial integrated utilities, and OPG and Hydro One in Ontario. Together these utilities serve 61 percent of Canadian electricity end-customers and generate 69 percent of our electricity.

I outline the potential equity value that could be unlocked from involving private capital in Ontario, BC and Quebec. I then provide a roadmap for the steps these provinces should take to protect the ratepayer interest and receive full value for their assets. In the other four provinces – Newfoundland, New Brunswick, Saskatchewan and Manitoba – I make the case for establishing a full user-pay system.

How Our Electricity System Works

Electricity systems can be considered in three independent parts – generation, transmission and distribution. Generation is the conversion of other energy sources to electricity – at a power plant that could be run on nuclear, natural gas or other fuels, or at a renewable energy facility generating electricity from water, solar or wind power. Transmission concerns the high voltage, tall lines that transmit power over long distances from power plants to consumers. Finally, distribution concerns the power lines running from a local transformer station to houses, and often the organization that sends household bills each month. As well, in some markets, an electricity retailer takes responsibility for billing and customer service. Generation represents roughly 60 percent of the typical electricity bill, while transmission accounts for roughly 10 percent and distribution up to 20 percent in Ontario (Morrow and Cardoso 2017). These systems are tightly integrated because at any given moment, the amount of electricity consumed must equal the amount supplied.[2]

1 It has offered to sell an additional 2.5 percent of the company to First Nations.

2 While energy storage is growing rapidly, it can be thought of as a consumer while the storage is charging, and a supplier while it is discharging.

Figure 1: Ownership of Canada's Electricity System

Ownership Model	# of Utilities	% of Distribution Customers	% of Power Generated
▪ Provincially owned Crown Corporation providing generation, transmission and/or power distribution (partially privatized in the case of Hydro One).	8	61%	69%
▪ Municipally owned local distribution company (LDC) in Ontario plus large municipally owned LDCs in Edmonton and Calgary.	57	27%	3%
▪ Other municipally or cooperatively owned LDCs in BC, AB, SK, QC, NB, or PEI, and territorially owned integrated utilities.	25	3%	Not significant
▪ 100% privately held utility or generator in BC, AB, ON, NWT, YK, province-wide in NS, PEI, and NL.	11	10%	28%

■ Others
■ Focus of Study

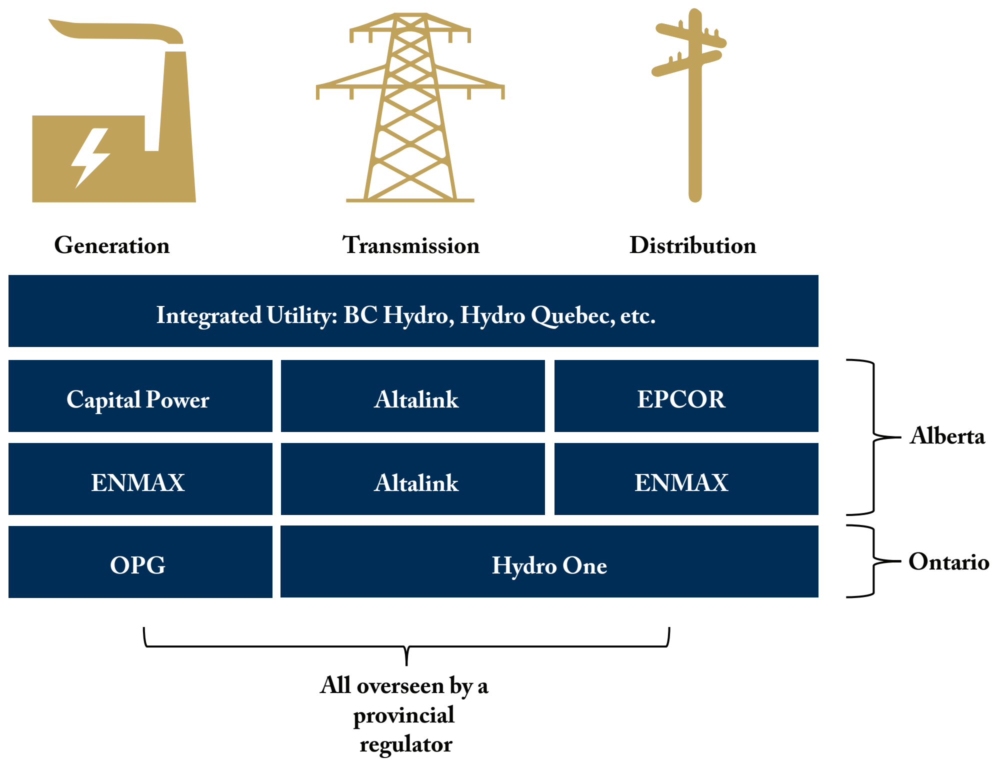
Sources: Author's calculations for 2015 based on Statistics Canada Table 127-0007, OPG 2016, Manitoba Hydro 2016, BC Hydro 2016, Hydro Quebec 2016, SaskPower 2016, NB Power 2016, Nalcor 2016 and relies on my previous analysis of distribution market in Robins 2017. 100% privately held utility or generator includes industry produced power for own consumption. I also include the Bruce Generating Station which is operated under a long-term lease from OPG by privately-owned Bruce Power.

Transmission and distribution lend themselves to a natural monopoly, because it is usually uneconomic for a second utility to run a wire to houses. As natural monopolies, these companies tend to operate with prices regulated by government. However, the electricity system is undergoing significant technological changes. Electricity generation is becoming much more distributed as households and firms are able to generate renewable energy on site and sell back into the grid. This might reduce the usefulness of the transmission and distribution grids, and could introduce more competition in these markets. This would reduce the value of these transmission and distribution assets to their provincial owners – a risk that these utilities did not previously face.

Meanwhile, generation can and has become a competitive market in many jurisdictions, with a government organization acting to determine which power plants may serve the market based on auctions that determine which plants have the lowest cost to serve.

Publicly or privately owned companies can and do enter any combination of these three markets. Canada has examples of companies focused solely on one segment, and on many combinations of the three (Figure 2).

Figure 2: There are Many Potential Configurations of Companies to Meet Electricity Needs



Note: There are countless permutations of market structure. This figure is only intended to illustrate several archetypal arrangements that exist in the country.

The Potential for Change

Existing Mixed Ownership Globally

The electricity system, both within Canada and globally, has substantial involvement of private capital. Regarding distribution, in six provinces some or all residents receive their electricity from a privately-owned electricity distributor, which operates under price-setting rate of return regulation. The UK, and two Australian states have fully privatized their electricity distribution (OFGEM 2013b; Kerin 2014), while 80 percent of transmission and distribution in the US is on privately-owned electric lines (Electricity Transmission and Distribution 2009). In all cases, there is a government regulator which sets allowable prices for these companies

The transmission system is fully privately owned in three provinces (Alberta, Nova Scotia and Prince Edward Island), and majority privately owned in Ontario. Around the world, the transmission system is privately-owned in the UK and in three Australian states (OFGEM 2013a). These assets are similarly regulated as distribution companies.

Similarly, in generation, there is a substantial role for private investors. In Canada, I estimate 31 percent of electricity comes from privately owned generation stations (Figure 1). In the US, 84 percent of electricity comes from privately owned generators (Zummo 2017), while in the UK more than 95 percent of electricity is generated by private companies (We Own It 2012). The New Zealand government sold 49.9 percent stakes in three electricity generation companies that generated 65 percent of New Zealand's power in 2013/14, after fully privatizing a fourth company that provided 23 percent of New Zealand's power in 1999 (New Zealand 2017). Australia also has a significant role for private generators.

The US electricity system developed predominantly in private hands, while the other countries profiled have transferred ownership to the private sector since the 1980s. In all cases, there is a robust debate over whether private provision of these services is cheaper or more expensive. These international examples show that the effects of private ownership are unlikely to be severely negative – and should be compared to the significant equity value that could be unlocked for other priorities.

Consumer Protection

Involving private investors in these utilities creates a need for a strong regulator that balances the interests of consumers and investors. These regulators both design market structures to determine which power plants can produce power, and determine allowable prices for the natural monopolies in transmission and distribution.

Prices must be set high enough to allow investors to achieve similar risk-adjusted returns as other potential investment options. At the same time, prices set too high will lead to value being transferred from consumers to producers, and economic inefficiency: consumers would reduce power consumption in response, even though power companies would be willing to provide additional electricity at a lower price. The result is lower overall welfare, while producers capture additional profits at the expense of consumers.

This power is balanced by the regulator. At the same time, the regulator must be independent of the political pressures of the government of the day. Electricity prices are a politically sensitive issue and governments often intervene to stop rate increases (Goulding 2013). This reduces investor confidence in their ability to earn necessary returns and causes reduced private participation in the market.

In Ontario, this role is played by the Ontario Energy Board (OEB) which sets rates for all of the transmission and distribution sectors and for some generation, while in Alberta this role is played by the Alberta Utilities Commission (AUC), which sets rates in the transmission and distribution sector. Both boards oversee an independent system operator, which manages a competitive market for generating capacity and oversees the generation and transmission system on a minute-by-minute basis. Both Alberta and Ontario have changes in their generating market structure ongoing. These two regulators have experience regulating existing private companies in the electricity sector. British Columbia and Quebec have independent price-setting regulators as well, although they do not regulate private-sector electricity providers, except for a single privately owned electricity distributor in BC. However, they do regulate the privately owned and operated natural gas distribution systems. As well, the BC utility commission is restricted from reviewing certain types of investments.

Other provinces, without substantial roles for the private sector in the electricity sector have less independent regulators. For example, final price-setting decisions are made by the provincial cabinet in Saskatchewan, and the provincial government retains responsibility for approving the capital plans of Manitoba Hydro.

Risk Transfer

Investing in new electricity generation, transmission and distribution is risky, because nobody can know with certainty what future electricity demand will be. Until the 2008 financial crisis, electricity demand was steady – however, electricity demand declined significantly after that and has yet to recover. Investments made under the assumption that the previous trend in power demand would continue have become unnecessary, but they still impose costs on the system. These costs can either be borne by ratepayers or by investors – and with a publicly owned utility they are mostly the same people.[3]

Figure 3 demonstrates what has occurred in Ontario. Electricity demand was steady from 2006 to 2008 at between 152 and 159 TWH.[4] However, since the financial crisis demand has been lower – between 135 and 147 TWH. Ontarians are simply using less electricity then before. A critical driver of cost is peak capacity – the system must be able to deliver enough electricity to meet demand at the highest moment, otherwise brownouts occur. However, delivering peak capacity is expensive, because by definition, most of the time these plants will not be used. The 20 highest-demand days in Ontario occurred between 2002 and 2007 at above 25,349 megawatts, while in 2015 the highest demand peak was at 22,516 MW. The result is a larger gap between our electricity supply and our demand.

Not all of this demand reduction was unforeseen. Over this period, Ontario made significant investments in electricity conservation efforts – but then procured supply against its demand forecast. This capacity was procured on fixed long-term contracts – typically 20 years. As a result, Ontarians must pay for the supply, whether they use it or not. With lower consumption and higher commitments to pay for supply, the price per unit rises – and the result is higher electricity bills, even for consumers whose consumption didn't change.[5] In the current market design, ratepayers bear the risk of misjudging demand.

Forecasting demand accurately is not only difficult, but has real costs of error. When demand is overestimated, we overinvest in supply and have additional costs, but when we underestimate demand we have system reliability problems. These reliability problems make it prudent to have some additional system capacity.

Well-designed electricity markets can transfer the risk of investing to investors. This is not as important a distinction if the investor is also a Crown corporation – either way the citizens largely bear the risk. But if private investors invest in new capacity, the risk can be transferred to them, so misjudging demand imposes costs on investors – not the electric or tax bill.

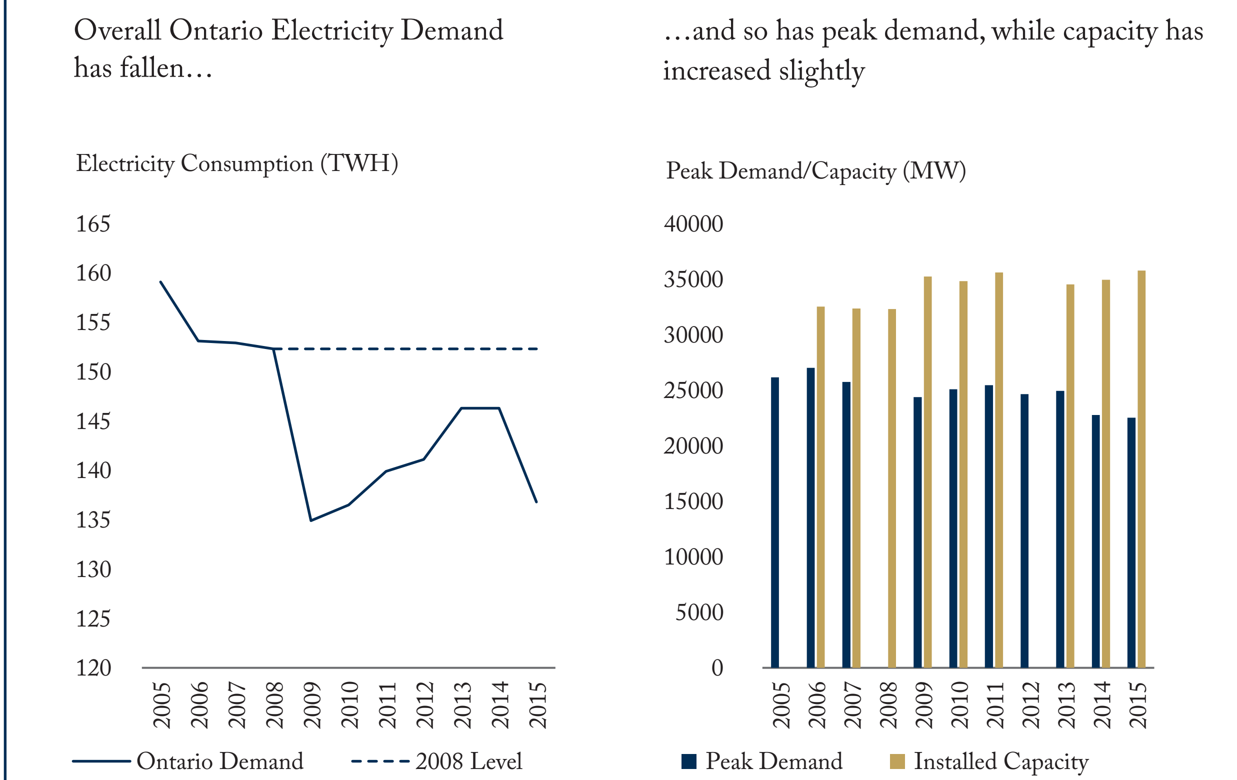
This approach has higher nominal costs – private investors will seek returns in exchange for bearing demand risk. In many cases, this premium could be quite significant as the risk is large. However, in exchange the ratepayer is not exposed to the cost of inaccurate demand forecasting. The ultimate impact on costs will be

3 Renters may not pay their electricity bill directly, however it is a component of their rent costs. A rise in electricity rates for non tax-paying government entities would increase their costs, which would ultimately be passed on to taxpayers through taxes. Some buyers, such as out-of-province or unprofitable industrial buyers, are also not taxpayers.

4 A TWH – terawatt-hour – is one billion times larger than a kilowatt-hour – which is the basis on which residential electricity consumption is based. Ten billion 100 watt lightbulbs, left on for one hour would consume one TWH.

5 In Ontario, consumers are charged the difference between the market price and contracted price through the Global Adjustment.

Figure 3: Changing Demand in the Ontario Electricity Market



Source: Author's Calculations from Statistics Canada Table 127-0008 and Table 127-0009, Morrow and Cardoso 2017 and IESO n.d. Missing data points are not included in the Statistics Canada data series.

determined by whether a competitive market can better find the appropriate supply/demand equilibrium than a central system planner. If the market can be more efficient – like it is in most products – than total costs (nominal purchase costs and costs of risks incurred) to the ratepayer will be lower with a competitive market.

There are many examples internationally of markets that have successfully transferred this risk to private investors. The most common way to do this is with a capacity market – variants of which are used in 32 US states (Goulding 2013), the UK (OFGEM 2014).Capacity markets are also a feature of announced market reforms in Ontario and Alberta (Shaffer 2016).[6] Australia and New Zealand similarly transfer risk to private investors, although with a market design that accepts more volatility in minute-by-minute electricity prices in exchange for even more transfer of demand risk to the private sector.

6 Some Albertan producers have simultaneously returned their power purchase arrangements to the balancing pool – transferring future costs from investors to consumers. While subject to ongoing litigation, this is possible because of changes in Alberta climate change law and a clause in the legal agreements – not a function of the capacity market design (Trynacity 2016).

Table 1: Equity Value of Analyzed Provincially-owned Electricity Companies

Airport	2015 EBITDA (*$ million*)	Net Debt (*$ million*)	Estimated Equity Value	Net Book Value	Market Premium over Book (*percent*)
Hydro Quebec	8,084	49,860	$29 billion	$19.7 billion	7 – 54
BC Hydro	2,878	19,914	$3 – $9 billion	$4.6 billion	-32 – 94
Hydro One	936	5,349	$7.1 billion	$5.1 billion	41
Total	**11,925**	**75,123**	**$31 to $45 billion**	**$29.3 billion**	**7 – 54**

Source: Author analysis of S&P Capital IQ Data. Note for Hydro One EBITDA and Net Debt are portion attributable to Province of Ontario (i.e., 49.9% of balance sheet value) and market value is as of 5/11/2017.

In a capacity market, electricity generators are compensated in two ways: a price paid for energy actually dispatched – set by minute-by-minute supply and demand, and a price paid for a commitment to provide capacity at times of high demand, set in an auction a few years in advance (Goulding 2013). Since these capacity payments are only fixed a few years in advance, the quantity of capacity purchased can respond much more quickly than under long-term fixed price agreements like those that exist in Ontario. This transfers the demand forecasting risk from the ratepayer to the investor.

Since in the capacity market generators bear more risk, they demand higher wholesale prices to compensate. However, whether electricity prices paid by end-consumers are higher or lower is determined by whether the market is better able to manage demand forecasting risk than the central agency which determines how much incremental capacity to add (Castalia Strategic Advisors 2013). In most other areas of the economy, we rely on markets as a better way to manage these risks – and there is not a compelling reason why electricity is different.

What Canadians Own

This section of the analysis focuses on the value of Hydro One in Ontario, BC Hydro and Hydro Quebec. The economics of other provincially owned electricity companies are addressed in the penultimate section of this paper. Recent transactions in the Canadian electricity sector, as well as publicly traded electricity companies provide a guide to how institutional investors would likely value these companies (see Box 1 for detailed methodology). This analysis suggests that the three provinces own equity stakes worth between $31 and $45 billion – a 7 percent to 54 percent premium over book value (Table 1). I use book value as a proxy for replacement value of these assets – since these assets were built in the past, it would likely cost more to replace the assets than their recorded value. When the market value of an asset is greater than its cost to create, it provides an investment signal to private investors, and vice-versa.

BC Hydro's valuation range spans the current book value of equity – although given its transmission and distribution assets, it is likely to trade in the upper half of the range. If the transaction occurred at the low end of the range, the government of BC would be forced to recognize a loss on the sale. While this presents a political barrier – it would not be an economic loss, rather a recognition that the assets are not worth as much as recorded on the government's books.

Box 1: Financial Valuation Methodology

I used a standard five-step methodology to establish indicative values for these electricity utilities:

1. I calculated Earnings Before Interest, Taxes, Depreciation (EBITDA), a common metric used as a proxy for free cash flow in port valuation, based on 2015 financials for each utility
2. Where sufficient public information is available to make possible – for Hydro One, OPG and Hydro Quebec – I separated financial information for rate-regulated transmission and distribution from generation assets because less risky transmission and distribution cash flows are more valuable.
3. I valued Hydro One based on market capitalization at May 11, and valued standalone transmission and distribution assets at 1.125x EBITDA – based on the price paid recently for Altalink – other transactions in Ontario have been at somewhat higher multiples.
4. I established a valuation range of 8x to 10x EBITDA for the integrated utilities or standalone generation based on publicly traded power generators and integrated utilities. Utilities with a higher mix of transmission and distribution will likely trade nearer the high end of the range (i.e., Hydro One, a pure transmission and distribution company trades at 13x EBITDA). The industry average in North America is 8x-9x EBITDA (Ernst & Young 2016).
5. I applied multiples to the adjusted EBITDA of each of the utilities to estimate total enterprise value and then subtracted net debt (value of debt less unrestricted cash and cash restricted by debt covenants).

The estimated revenue and EBITDA growth rates of these utilities, as well as the investor's perceived risk, will significantly influence the EBITDA multiple an investor is willing to pay. Both these variables have significant uncertainty. Critical government decisions regarding transaction structure (e.g., regulatory framework, statutory requirements, market design) will affect the sale value.

Involving private institutional capital in Hydro Quebec and BC Hydro would make them subject to federal and provincial corporate tax. This represents a value transfer from the provincial to federal government. Provinces would receive an upfront payment for the equity and a stream of provincial tax revenues, in exchange for foregoing their current dividends. Provinces would forego approximately $2.5 billion in annual cash flows in exchange for a $31-$45 billion payment for their equity. This represents 13-18 years of these payments made upfront (Figure 4).

Provinces could also sell partial equity stakes in these utilities – the course taken by Ontario with Hydro One. Selling a partial stake provides an opportunity to capture some of the upside, if the new owner improves profitability (but also exposes the province to downside in the event of poor performance). If a province sold a partial stake it would receive a portion of the upfront value in exchange for a proportionate reduction in dividends.

Selling partial equity stakes is often seen as more politically viable than a full sale, in part because it still offers the province some influence on the board of the company. A mixed ownership model has two potential drawbacks. First, the board has mixed public and private interests that lead to conflicts and therefore decrease

Figure 4 – Financial Impact of Sale of Analyzed Utilities

	Current Dividends	New Tax Revenues	Net Change in Annual Provincial Cashflows	Upfront Value of Sale
Hydro Quebec	$2,360 million	$388 million provincial $489 million federal	($1,972 million)	$21-$29 billion 10-15 years of cash flows
BC Hydro	$326 million	$101 million provincial $138 million federal	($225 million)	$3-$9 billion 13-39 years of cash flows
Hydro One	$258 million	No changes – already subject	($258 million)	$7.1 billion 27 years of cash flows
Total	**$2,944 million**	**$489 million provincial** **$689 million federal**	**($2,455 million)**	**$31-$45 billion** **13-18 years of cash flows**

Source: Author's analysis based on company financials.

the likelihood of success – regardless of how it is defined by the various parties (Mintz 2017). Second, the ongoing provincial stake may mean that the province feels less pressure to strengthen the regulatory institutions to protect consumer interests. Either the regulatory process is strong enough to protect consumers and therefore involving private capital is appropriate, or it isn't.

How to Involve Private Capital Successfully

Four enabling changes are necessary to involve private capital in a way that protects the public interest. All four changes are meant to reduce uncertainty around the future of the businesses, because with reduced uncertainty, investors will be willing to accept lower returns – and thus pay higher prices. First, pricing needs to be established at a level that allows investors to earn market risk-adjusted returns on the capital they invest. Absent this level of pricing, investors will not reinvest in the system, leading to a slow degradation of service quality. Before sale, changes in the price level balance the interests of ratepayers and shareholder – largely the same people – and so the balancing has little effect. After sale, changes in the price level transfer resources between ratepayers and shareholders, who are no longer the taxpayer. If future price changes are likely to be necessary to ensure investment, making those changes now is critical to ensure that investors pay for that value in the upfront purchase price.

Second, to enforce an appropriate pricing balance between consumers and investors, regulators would need to be strengthened, and made completely independent from political interference. The market should be able to make investment decisions, confident in the future of the regulatory system, by responding to price signals within the environmental regulation framework set by government. This means that governments should restrict themselves from intervening to adjust allowable rates of returns, make technology decisions, or affect the rate-setting process. This requires strong legislation to empower an independent regulatory board. Involving private capital may strengthen the independence of the regulator, since under the status quo, when a province intervenes to adjust the balance in consumers favour, it only harms its own financial interest – and therefore there is no constituency opposing the intervention.

Third, is designing a market for generation assets, which can be a competitive market. All three jurisdictions should establish true capacity markets for generation capacity, as outlined previously in this paper. This is necessary to ensure that risk is transferred from ratepayers and taxpayers to investors – the key source of increased public value from these transactions.

Finally, provinces need to explore breaking up the generation assets of these companies into individual companies. A competitive marketplace where one owner controls the vast majority of supply – which would be the situation in BC and Quebec – is unlikely to attract new private investment, since the single large company could manipulate prices in the marketplace. The large relative size of OPG was one of the challenges in establishing competitive wholesale electricity markets in Ontario. By creating multiple, competitive privately owned generating companies, the provincial governments can create a competitive wholesale electricity market to drive prices down.

How to Set Up Other Utilities to Involve Private Capital

Using the same valuation approach for the other five provincially owned electricity companies, based on their current financials, I found that a private investor would likely be unwilling to pay more for these companies than the value of outstanding debt. This means that provinces would face a cash shortfall to repay debt if they were sold.

One exception is Ontario Power Generation, where my analysis suggests that the utility's equity value ranges from $0 – $5 billion. However, this utility has long-dated nuclear clean-up liabilities, and I have not evaluated whether the reserves OPG holds for those liabilities are reasonable. These long-dated liabilities may reduce the price a private investor is willing to pay. One option for OPG would be to consider a separate sale of its hydroelectric assets. These assets do not bear the same uncertainty over future liabilities and therefore are a more viable candidate for sale. This would leave OPG holding a less attractive portfolio on average – as the most attractive assets were sold. In all other cases, at current price levels, the value of these assets is likely to be below the value of outstanding debt.

There are two reasons why this could occur – owning assets with costs exceeding their economic value, or inadequate price levels. When the estimated market value of a firm is below its replacement value it signals that the firm should be unwilling to reinvest to maintain its current size – the cost of rebuilding its assets is worth less than their value on the market. When it comes time to replace aging assets, a firm would choose not to invest. While determining accurate replacement costs is difficult, most electricity assets have long useful lives – meaning a significant portion was built many years ago. Since the price level has generally risen over the last several decades, the replacement cost is likely higher than the book value of the assets. Therefore, involving private capital in these utilities would likely lead to less investment.

If the cause of this shortfall is that some assets are still recorded on the balance sheet, but no longer have operational value, because they are unnecessary for meeting customer needs, then ceasing to reinvest in those surplus assets improves economic efficiency. This could occur if poor investment decisions were made in the past, future investments are being made in assets with inadequate returns, different customer needs changed requirements, or technological change meant different assets were more advantageous. The economic cost of building these surplus assets has already been incurred, but has not been recorded financially. Selling these assets to the private sector would recognize this cost in the province's accounting and then impose increased discipline on future investment decisions in these assets. If capital investment more closely aligns with needs, consumer prices will fall.

The second cause may be inadequate price levels. Electricity prices should be set at a cost-recovery level – including returns for investors to incentivize necessary reinvestment in the system. Prices set too high result in unnecessary costs for users and economic rents captured by producers. Prices set too low mean the users are subsidized by investors – and a private investor would reduce investment in the future. This results in overconsumption. In both cases, the result is economic inefficiency. For the other provincial electricity utilities, net income is very close to zero. This situation means that the province is not receiving compensation for its equity investment in the utility, and that taxpayers are subsidizing the cost of electricity for ratepayers. Further, it prevents appropriate price signals regarding the cost of electricity from flowing to end-consumers. These issues must be addressed before these provinces can consider involving private capital.

If the cause of low asset values relative to outstanding debt is that the utility has significant surplus assets that do not need to be replaced, then involving private capital would add discipline to future investments and potentially lower costs for ratepayers. However, if the issue is inadequate price levels, then private investors would not make necessary investments and the system's reliability would suffer.

Conclusions

Provincial electricity utilities are significant assets on the books of provincial governments. They represent the significant investment of public dollars over many decades. But continued ownership is not necessary to achieve government objectives of affordable prices for consumers – strong regulators to protect consumers from abuse of monopoly power is sufficient. Three provinces currently have $31 – $45 billion in equity invested in these utilities – and other provinces have significant investments in utilities as well, although they are not likely valuable to investors given their current regulatory structure. This value can be redeployed to other projects where public investment is necessary to achieve policy objectives. This potential redeployment could make significant progress towards provincial infrastructure investments: investments that have returns to society, but unclear financial returns and therefore struggle to attract private capital.

Involving private capital in this market has been done successfully in the US, UK, Australia and New Zealand. In the status quo, ratepayers bear the risk of mistaken demand forecasts, and carry the costs of overinvestment on their electricity bills for years. By involving private risk capital, provinces can transfer this risk to private investors. If the market is better able to manage this demand risk than central government decisions – a view we take in most other sectors of the economy – then overall electricity prices for consumers will fall.

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