Power prices in context: comparing Alberta delivered electricity prices to other Canadian provinces on a level playing field

Prepared for the Independent Power Producers Society of Alberta (IPPSA), the Industrial Power Consumers Association of Alberta (IPCAA) and the Utilities Consumer Advocate (UCA) by London Economics International LLC

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In 2004, London Economics International LLC (LEI) prepared a paper for the Independent Power Producers Society of Alberta (IPPSA) entitled "Paying the full cost of power: a comparative analysis of selected Canadian provinces." This 2004 paper identified the ways in which power costs to final consumers are suppressed in other Canadian provinces and demonstrated the potential benefits of the Alberta approach to consumers and taxpayers. In 2010, IPPSA requested that LEI update the paper to include discussion of the impact on industrial consumers and incorporate recent developments. As in 2004, we find that outside of Alberta, prices to final consumers in some provinces significantly underestimate the full cost of power. Furthermore, in some cases, the market structure in provinces outside of Alberta appears to invite government intervention, leading to erratic and ultimately costly policies for electricity consumers. The Alberta market, by contrast, continues (with the exception of transmission) to provide more transparent market signals and contributes to economically efficient decision making among both generators and consumers. From 2009-2010, rates to end-users rose across Canada, but fell in Alberta thanks to a market design which more clearly aligns prices with supply, demand, and fuel market dynamics. When taxation, capital structure, return, and opportunity costs vis a vis export pricing are accounted for, the cost of power in other provinces is higher than what is reflected in end-user rates. Although recent legislation regarding transmission gives cause for concern, when compared fairly, Alberta's prices are competitive across Canada. This assumption still holds when the cost of announced transmission infrastructure investments is considered through 2015.

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1 How is Alberta different from other Canadian provinces?

Power costs in Alberta more closely approximate the full economic cost of providing electricity than do power costs in other provinces. Although delivered power prices in other provinces may appear lower, such prices mask implicit subsidies, reflect lower effective tax rates on utilities, and incorporate cross subsidies provided by export sales. By contrast, in Alberta, electricity price signals are less muted by government intervention and are highly responsive to supply-demand dynamics.[1] Alberta was the only province to see power prices fall in response to the recent recession. Appropriate price signals lead to more efficient consumption and investment decisions, resulting in the lowest efficient sustainable prices in the long run.

1.1 Alberta relies on competitive market forces to set the price of wholesale generation

Prices for generation in Alberta are set according to bids from generators into a power pool. Generation is fully unbundled from transmission and distribution. The Alberta wholesale generation market has been in operation for over 14 years. Over $5 billion[2] has been invested in new generation in the province and a number of new players have entered the market since it was liberalized. All Alberta consumers have the opportunity to participate in the spot market and to hedge against changes in those prices.

The generation component is only one portion of the consumers' final bill. Transmission and distribution also impact the delivered price of electricity. Like many provinces, Alberta is planning substantial upgrades to its transmission system. While these upgrades will increase reliability, they will, over the near term, also contribute to an increase in delivered prices.

For distribution, Alberta is in the midst of adopting an advanced regulatory structure which provides explicit incentives for efficiency, in real terms, absent significant capital expenditures;[3] this system will help to drive down the distribution portion of customer bills. Although some distribution companies plan large capital expenditures, in growing service territories the cost of new capital expenditure may be partly absorbed by the increase in customers and volumes sold.

1.2 Other provinces largely rely on a form of cost-of-service ratemaking

Unlike the Alberta market, which consists of multiple generators operating on short to medium term market-based contracts or spot sales, most other Canadian provinces are dominated by a single vertically integrated provincially owned utility. In Manitoba, Saskatchewan, and Quebec, the provincially owned utility dominates every aspect of the value chain. In British Columbia (BC), the province has encouraged new supply from private generation under

[1] While Alberta has generally done a better job than other provinces with respecting the independence of market and regulatory institutions, The Electric Statutes Amendment Act (formerly Bill 50) is an exception. Preference shown towards transmission investment may lead to less economically efficient outcomes in some cases.

[2] Government of Alberta. "*Electricity and You*". <http://www.energy.alberta.ca/Electricity/1475.asp>. October 12, 2010.

[3] Alberta Utilities Commission. "*Regulated Rate Initiative - PBR Principles*". July 15, 2010.

contract to the provincial utility; BC has also experimented with spinning off (but under continued provincial ownership) transmission operations, though the government (wrongly in our opinion) reintegrated BC Transmission Co. into BC Hydro, effective July 2010.[4] In the Atlantic provinces, privately-owned vertically integrated utilities are the norm; in Newfoundland, Nunavut, and Yukon, in addition to BC, some small private utilities or IPPs exist alongside the provincial utility.

Figure 1. Key market design elements

Province	Utility	Market Share, Generation	Market Share, Load	Provincially Owned	Unbundled?	Organized Markets?
Alberta	Market consists of 10 distribution companies	Currently over 50 generators	NA	No	Yes	Yes
British Columbia	BC Hydro	94%	95%	Yes	Yes	No
Manitoba	Manitoba Hydro	100%	100%	Yes	No	No
New Brunswick	NB Power	100%	100%	Yes	No	No
Newfoundland and Labrador	NF&L Hydro	95%	97%	Yes	No	No
Nova Scotia	NS Power	97%	95%	No	No	No
Nunavut	Qulliq Energy	98%	100%	Yes	No	No
Ontario	Hydro One	64% (OPG)	85%	Yes	Yes	Yes
PEI	Maritime Electric	90%	90%	No	No	No
Quebec	Hydro Quebec	100%	93%	Yes	Yes	No
Saskatchewan	SaskPower	98%	89%	Yes	No	No
Yukon	Yukon Energy	93%	100%	Yes	No	No

Source: Utilities annual reports, Regulators; unbundled entities may be distinct subsidiaries under common ownership

As discussed later in this document, Ontario operates under a different model, with a provincially owned generation company and a provincially owned wires company, municipal and private distribution utilities, and a power authority which procures most generation under long term contracts. Although Ontario has a real time market, this market has increasingly been marginalized.

In those provinces outside of Alberta which have private sector generation, such generation is largely compensated under long term, quasi-government guaranteed contracts. Costs for generation from the incumbent utilities, and from the independent power producer (IPP) contracts, are passed through to customers, regardless of whether that generation is needed or not. The ability to pass costs through to customers erodes financial discipline and can lead to oversupply. Incentives to planners are asymmetric: in the event of oversupply, customers pay the costs; in the event of outages due to undersupply, political outcry ensues. This dynamic can lead planners to rely on unrealistically robust load forecasts and to approve new build which may not be needed. During an economic downturn coupled with increased attention to conservation, the consequences can be costly.

By contrast, in a system like Alberta's, if generators overbuild, it is shareholders rather than customers who bear the burden. This difference in risk allocation leads to more efficient decision-making and ultimately lower costs.

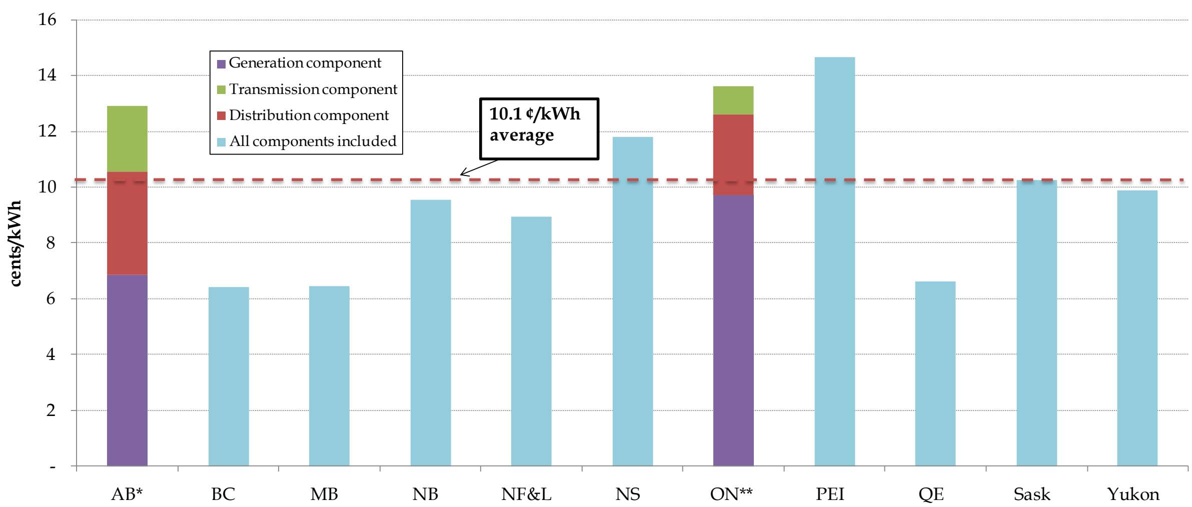
[4] British Columbia Hydro. "*Clean Energy Act and general integration*". November 15, 2010. <http://www.bchydro.com/about/company_information/partners___vendors/transmission_vendors.html>.

2 How do delivered costs of electricity to final consumers in Alberta compare to delivered costs of electricity in other provinces?

A review of 2009 residential and industrial rates[5] across Canada reveals that Alberta has neither the highest nor the lowest rates in Canada. Furthermore, while rates in other provinces have been rising, customers in Alberta experienced a decrease in wholesale power costs in 2010 depending on their contract position.

2.1 Residential

Figure 2. Rates to final residential customers in Canadian provinces, 2009



Source: Utilities annual reports, Regulators

**Alberta rate is the weighted average of Regulated Rate Options for ENMAX, EPCOR, FortisAlberta, and ATCO service territories plus transmission and distribution charges.*

***Ontario rate is for Hydro One.*

Note: The residential rates in Nunavut range from 39.39 cents/kWh in Iqaluit to as high as 81.72 cents/kWh in Kagaaruk.

Alberta weighted average residential rates were estimated at $0.129 per kWh in 2009.[6] Across Canada, residential rates in 2009, when expressed on a volumetric basis, ranged from $0.064 in

[5] The term "rate" in this paper refers to the all-in delivered cost to consumers and can either reflect a tariff established wholly by a regulator or a combination of market prices and regulated components.

[6] It is important to note that while we use the weighted average RRO as a residential rate, customers have the option of signing long term contracts for a market price. As of February 2010, 28% of Alberta residential customers have signed such contracts. Government of Alberta. "Retail Market Review". April 15, 2010. Pg. 14.

British Columbia to $0.147 per kWh in Prince Edward Island. Most residential bills include a mix of fixed and volumetric components. In order to compare across provinces, we used the average monthly household consumption level for each province.[7] Each utility provides current and historical rates on their websites and the associated maximum consumption levels per tranche. To facilitate like-to-like comparisons fixed charges were converted to volumetric rates based on average customer demand. For Ontario, Hydro One was used as a representative. Ontario rates are the sum of energy (Regulated Price Plan rates established by Ontario Energy Board), transmission, distribution, and other charges such as debt retirement. Energy charges include wholesale energy and Global Adjustment (GA) charges.[8] For Alberta, the weighted average[9] Regulated Rate Options (RRO) for ATCO, ENMAX, EPCOR, and FortisAlberta service territories plus distribution and transmission charges was summed to arrive at the residential rates. For detailed calculations please refer to Appendix C: Residential and industrial rate calculations.

Alberta residential rates were 28% higher than of the Canadian average of $0.101 per kWh in 2009. When provinces with more than 50% hydro are excluded, Alberta was within 13% of the average of $0.115 per kWh for provinces without large hydro endowments.

2.2 Industrial

A similar range of rates can be found across Canada for industrial consumers. In 2009, the industrial rate in Alberta was estimated to be $0.07 per kWh. The lowest rates of $0.041 per kWh were found in Manitoba, while the highest rates of $0.13 per kWh were found in New Brunswick. Rates were calculated using the same process as was used for residential rates. As a benchmark, industrial customers were defined as those with monthly consumption of higher than 49,000 kWh.[10] Rates are generally taken from utilities' websites. For Ontario, all-in charges were calculated by adding transmission, distribution, the Global Adjustment, the Hourly Ontario Energy Price (HOEP) charges and other charges such as debt retirement. The GA is determined by averaging the data of the past 12 months; the HOEP is load-weighted for 2009.

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[7] Based on Natural Resources Canada estimates.

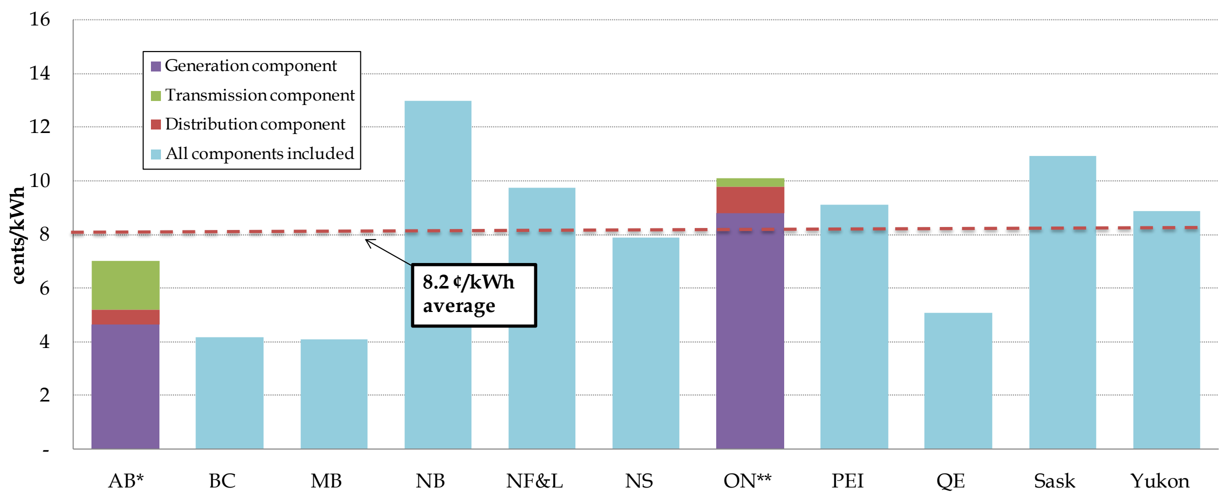
[8] There are two components of electricity commodity charges in Ontario: the Hourly Ontario Energy Price (HOEP) and the Global Adjustment (GA). The HOEP is the wholesale market price and is based on supply and demand, as balanced in real-time for each hour. The GA reflects the difference between market prices/revenues and 1) the regulated rate paid to OPG's baseload generating stations; 2) payments made to suppliers under contract with the Ontario Power Authority (OPA); and 3) contracted rates paid to non-utility and other resources. The GA is also the mechanism used to recover the cost of a number of other OPA administered programs, including demand response and conservation initiatives. Taken together, the HOEP and the GA reflect the "consumer price" of electricity in Ontario. For each contract class, the GA amount is determined by the difference between the contract/regulated price and price received in the market.

[9] Number of residential customers was used to arrive at the weighted average RRO.

[10] Based on lowest consumption level of largest industrial class definition in Canada.

Industrial rates for Alberta consist of wholesale energy prices,[11] as well as transmission and distribution charges for each utility. Rates are based on a customer-weighted average for ATCO, EPCOR, ENMAX, and FortisAlberta.

Figure 3. Rates to final industrial customers in Canadian provinces, 2009



Source: Utilities annual reports, Regulators

**Alberta rate is the weighted average unbundled rates for ENMAX, EPCOR, FortisAlberta, and ATCO. Transmission charges are based on AESO's total revenue requirement filed with AUC: "AESO 2010 ISO Tariff Application", pages 11-12.*

***Ontario rate is for Hydro One*

Alberta's positioning relative to other Canadian provinces with regards to industrial rates differs from trends found in residential rates. Industrial rates are slightly below the Canadian average for most provinces; when hydro-rich provinces are excluded, Alberta rates are among the lowest. Alberta's industrial rates are $0.07 per kWh compared to an average of $0.082 per kWh for all provinces and $0.096 per kWh for non-hydro dominated provinces.[12] When compared to industrial rates in the US, Alberta rates are also competitive; using US Energy Information Administration data for June 2009, Alberta industrial rates at average 2009 exchange rates were found to be lower than 32 US states.

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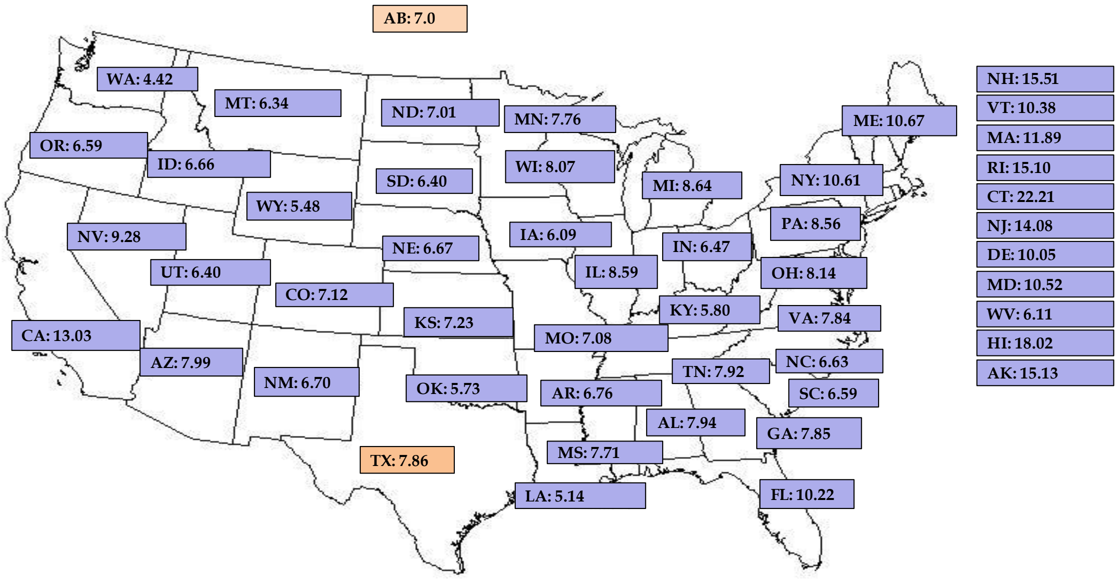
[11] Energy prices for Alberta are load-weighted using EPCOR estimates of monthly default supply energy prices, which incorporate the impact of a typical customer class load shape. We have used the five year (2006-2010) average load shape premium, as reported by EPCOR, for demand less than 75 kW. <http://www.epcor.ca/en-ca/Customers/electricity-customers/electricity-rates/default-supply-rates/Pages/actuals.aspx>.

[12] New Brunswick, Newfoundland and Labrador, Nova Scotia, Ontario, Prince Edward Island, Saskatchewan, and Yukon.

Figure 4. Comparison of Alberta industrial rates with US states, 2009



Source: US Energy Information Administration (EIA), "Monthly Electric Sales and Revenue Report with State Distributions Report", June 2010.

Note: All rates listed are as of June 2009 and are displayed in Canadian cents per kWh using average US dollar to Canadian dollar exchange rate in June 2009, Bank of Canada

2.3 Impact of announced rate increases

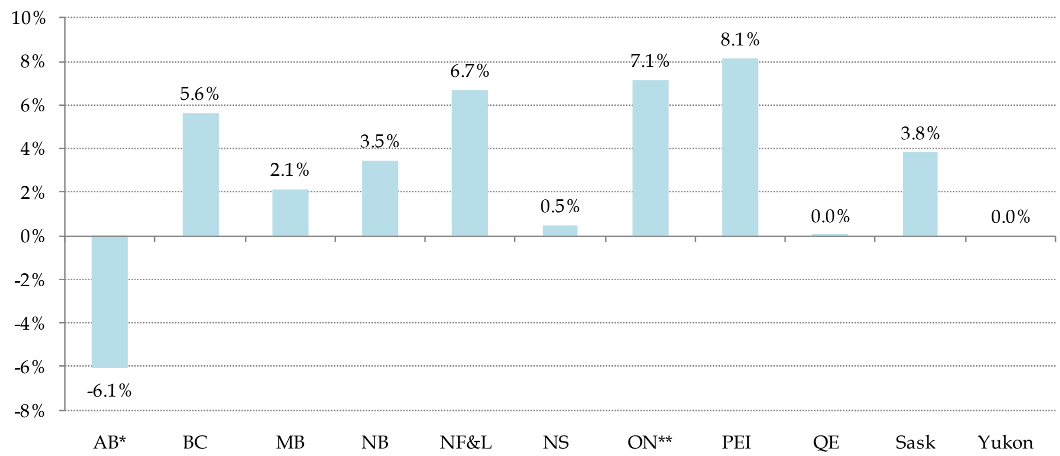
To date, announced rate increases have served to narrow the difference between rates in other provinces and Alberta. While Alberta rates have fallen consistent with trends in its wholesale generation markets, such as reduced load and historically low gas prices, rates in other provinces, which have not appropriately restructured their electricity sector, have risen. Below, we summarize rate increase announcements across Canada. Sources consulted for this section are listed alphabetically in Appendix A.

2.4 Recent rate changes

To ensure comparability, all rates and rate changes below refer to average volumetric rates per customer class; fixed components have been converted to volumetric based on average customer consumption.

- ***Alberta:*** on average, residential rates in Alberta have decreased since April of 2009 by approximately 6.1%. In addition, industrial rates in Alberta declined from 7.0 cents/kWh in 2009 to 6.9 cents/kWh in 2010, a decline of approximately 1.2%.

Figure 5. Percentage change in delivered rates to residential customers (2010 v 2009)



Source: Utilities annual reports, Regulators

**Alberta rate is the weighted average of Regulated Rate Options for ENMAX, EPCOR, FortisAlberta, and ATCO service territories plus transmission and distribution charges*

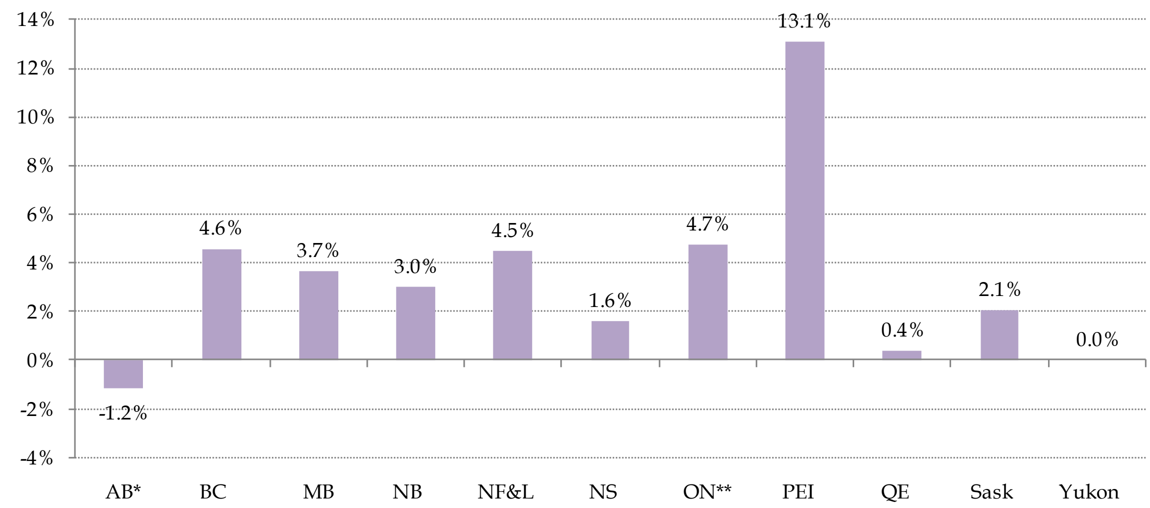
***Ontario rate is for Hydro One*

- ***British Columbia:*** BC Hydro has proposed a general rate increase of 6%. On March 15th, 2010, the British Columbia Utilities Commission (BCUC) approved the rate increase on an interim basis, effective April 1st, 2010. Residential rates increased from 6.40 cents/kWh to 6.76 cents/kWh and industrial rates changed from 4.16 cents/kWh to 4.35 cents/kWh, an increase which can be attributed to infrastructure upgrades.

- ***Manitoba:*** the Public Utilities Board has proposed an average of a 2.1% rate increase across all customer classes, which has been approved on an interim basis. The residential rates increased from 6.46 cents/kWh to 6.6 cents/kWh and the rate for industrial customers increased from 4.10 cents/kWh to 4.25 cents/kWh. Investments in new generation, transmission and distribution facilities were given as the reason for the rate increase.

- ***New Brunswick***: on April 9th, 2010, NB Power filed for a 3.5% rate increase to the Energy and Utilities Board (EUB) which would be effective from June 1st, 2010 onwards. The filing was approved on April 27th, 2010. The residential rates subsequently increased from 9.54 cents/kWh to 9.87 cents/kWh. Industrial rates jumped from 12.95 cents/kWh to 13.36 cents/kWh. This rate increase will allow NB Power to meet its commitment to eliminate the residential declining block rate.

Figure 6. Percentage change in delivered rates to industrial customers compared to 2009



Source: Utilities annual reports, Regulators

**Alberta rate is the weighted average all-in rates for ENMAX, EPCOR, FortisAlberta, and ATCO*

***Ontario rate is for Hydro One*

- ***Newfoundland and Labrador:*** effective July 1st, 2010, the overall electricity rates in Newfoundland increased by an average of approximately 6% across all customer classes.[13] This rate change was primarily the result of rising oil prices which caused an increase in the cost of generating electricity by Newfoundland and Labrador Hydro. The actual amount of the rate change will vary depending on the customer category and amount of electricity used. Residential rates increased from 8.93 cents/kWh to 9.53 and industrial rates increased from 9.75 cents/kWh to 10.19 cents/kWh.

- ***Northwest Territories:*** the Northwest Territories Power Corporation (NTPC) will keep rates constant for at least the next year. NTPC has not had any increase in general rates for the past two years.

- ***Nova Scotia:*** effective June 2010, electricity rates for residential customers increased from 11.81 cents/kWh to 11.86 cents/kWh and the rate for industrial customers increased from 7.90 cents/kWh to 8.03 cents/kWh. Rates have increased as customers are charged for the "Energy Efficiency and Conservation" program.

[13] Newfoundland and Labrador has increased rates twice over the past year.

- ***Nunavut:*** there has been no rate increase over 2010. The residential rates range from 39.39 cents/kWh in Iqaluit to as high as 81.72 cents/kWh in Kagaaruk. The industrial rates range from 31.84 cents/kWh to 71.98 cents/kWh.

- ***Ontario:*** on average, residential and industrial rates in Ontario increased by 7.1% and 5% respectively. The rates have increased to replace and maintain equipment nearing its end of life, build or upgrade facilities to keep up with customer growth, fund smart meter installations, connect renewable generation projects to distribution facilities, and pay for capital costs for physical infrastructure and systems.

- ***Prince Edward Island:*** effective April 1st, 2010, the rate for PEI residents increased from 14.66 cents/kWh to 15.85 cents/kWh. The rate for industrial customers increased from 9.11 cents/kWh in 2009 to 10.30 cents/kWh in 2010. In 2010, the Regulatory and Appeals Commission (IRAC) approved the Energy Cost Adjustment Mechanism formula to be used to calculate each month's rate. ECAM is a mechanism to manage energy related cost changes that are beyond the control of the Maritime Electric.

- ***Quebec:*** The Régie de l'énergie approved an increase in electricity rates of approximately 4% across all customer classes, effective April 1st, 2010. This rate increase was set to cover a drop in commercial sales. Electricity rates for residential customers increased from 6.6 cents/kWh to 6.61 cents/kWh while the rates for industrial customers increased from 5.08 cents/kWh to 5.10 cents/kWh.

- ***Saskatchewan:*** the Government of Saskatchewan approved an average rate increase of 3.8%, effective August 1st, 2010. The Saskatchewan Rate Review Panel (SRRP) had originally asked for a 7% rate hike across all customer classes. Residential rates increased from 10.24 cents/kWh to 10.63 cents/kWh and industrial rates increased from 10.94 cents/kWh to 11.17 cents/kWh. Typical residential customers will see an increase of $5-10 per month on their power bills. Infrastructure upgrades were the reason for the rate increase.

- ***Yukon:*** there has been no rate increase over the past year in the Yukon. Residential customers in the Yukon pay 9.87 cents/kWh and industrial customers pay 8.89 cents/kWh.

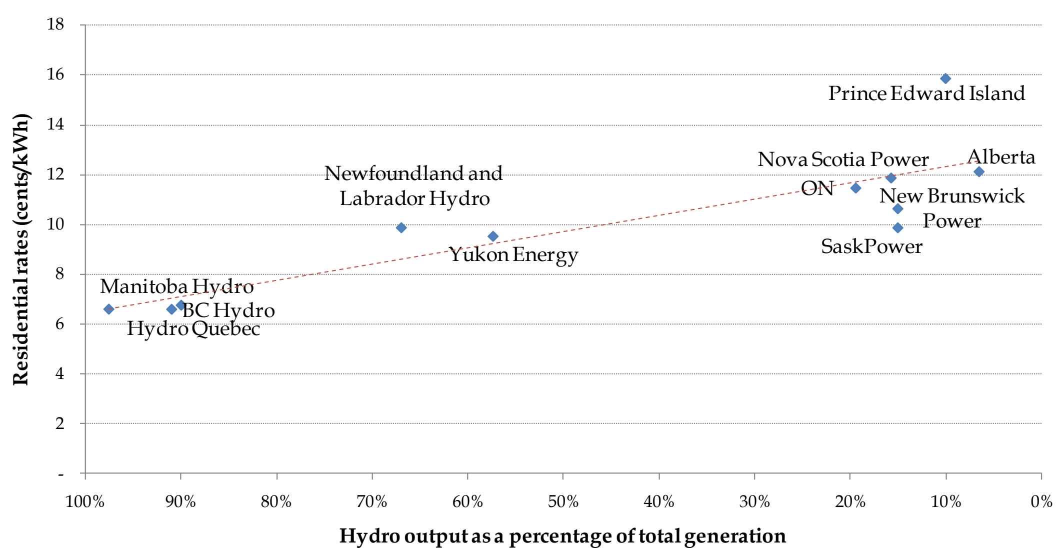
3 Delivered costs to final consumers in other provinces may not fully incorporate the full cost of power

Rates to final consumers across Canada differ for several reasons: the proportion of hydroelectric generation in their capacity mix, the extent to which utilities are capitalized consistent with commercially reasonable norms, provincial owners accepting below market equity returns, differences in taxation, and the treatment of export revenues. Below, we explore each of these issues in greater detail and calculate the combined impact on rates for each province.

3.1 Differences in initial endowments

One of the primary drivers of rate differences is the extent of hydroelectric generation in a province. As the graphic below shows, although Alberta is among the least well endowed with cheap resources, with only 6.5% of energy from hydroelectric generation, Alberta rates are nonetheless lower than some other provinces with more hydro. Furthermore, although shale gas has changed the dynamics of natural gas markets in North America, Alberta is favorably positioned with regards to the levelized cost of fossil fuel generating capacity additions relative to those provinces which are further away from natural gas fields.

Figure 7. Percentage of hydro output against level of rates, 2010



Source: Utilities annual reports

As a proxy for the extent to which hydro endowments contribute to lower prices to final consumers, prices in the hydro dominated Pacific Northwest, as evidenced by the Mid-C pricing point, averaged $36.11[14] per MWh in 2009,[15] while Alberta wholesale generation prices averaged $47.81 per MWh over the same period. This suggests that as much as 2 cents per kWh of the difference in rates between Alberta and hydro-dominated provinces may be explained by the difference in the underlying resource mix.[16] Figure 7 supports this conclusion; differences in hydro endowments may explain at least half of the difference in rates between Alberta and provinces such as Manitoba, British Columbia, and Quebec.

3.2 Levels of leverage and impact on overall provincial debt burden

Along with the maritime provinces, Alberta is among the few provinces which do not own provincial utilities. Provincially-owned utilities may unfairly benefit from an implicit guarantee or halo effect around their debt because investors may assume that, regardless of the fact that the utility is at arm's length from the province, it is unlikely that the provincial parent would allow its utility to default on its debt. In the cases where a utility does pay its parent for an explicit debt guarantee, the amounts paid for the guarantee may be less than the market cost of similar guarantees, or such guarantees may simply be unavailable in the public capital markets. Regardless, a review of long term debt to total asset levels across provinces shows that provincially-owned utilities are significantly more leveraged than those which are privately owned.

As Figure 8 shows, many provincially-owned utilities have long term debt to asset ratios of over 65%, in contrast to approximately 50% for private regulated utilities. Utilities in Alberta average 54%,[17] and independent generators in Alberta average 61%.[18]

Using the approved returns on equity in each of the respective provinces, and deleveraging the balance sheet of each of the utilities, we can estimate the extent to which implicit debt guarantees suppress rates to final consumers. We calculate this by adding the amount of equity necessary to bring the utility to a 50% debt[19] to assets capitalization ratio, multiplying this additional equity amount by the difference between debt costs and allowed equity returns, and dividing the total by domestic volumes sold in 2009. Figure 9 shows the additional increment to rates in cents per kilowatt hour. The increase for residential customers ranges from 2% to 8% and the increase for industrial customers ranges from 2% to 15%.

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[14] In Canadian dollars using 2009 average US dollar to Canadian dollar exchange rate, Bank of Canada.

[15] Ventyx Energy Velocity.

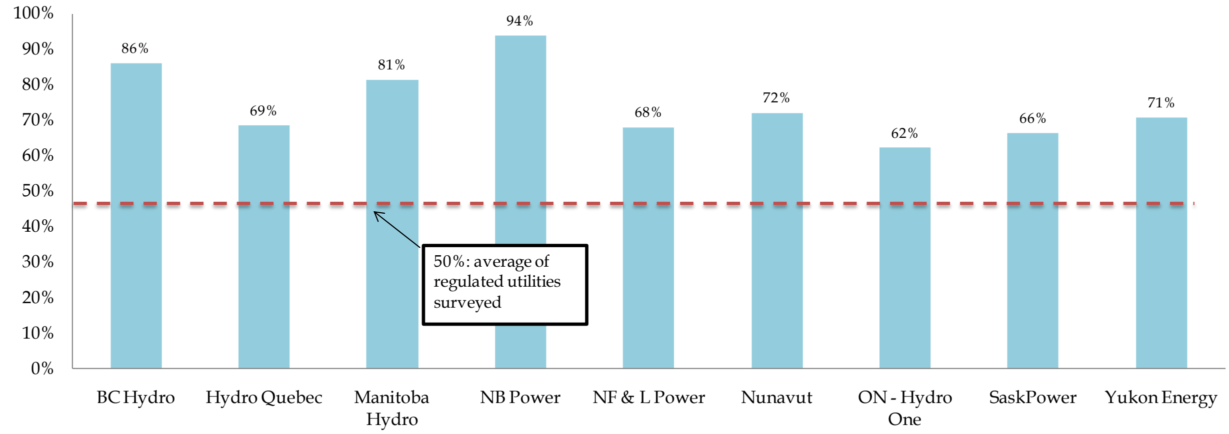
[16] While regional markets may also have other differences, such as a predominance of ratebase generation, the underlying fuel mix and supply-demand balance is a key explanator for regional price variations.

[17] EPCOR and ENMAX. Annual reports, 2005-09.

[18] Maxim Power Corporation, TransAlta, and TransCanada Corporation. Annual reports, 2005-09.

[19] While the norm used in our calculations is based on actual averages, LEI believes it is at times appropriate for regulated utilities to have higher levels of debt in their deemed capital structure.

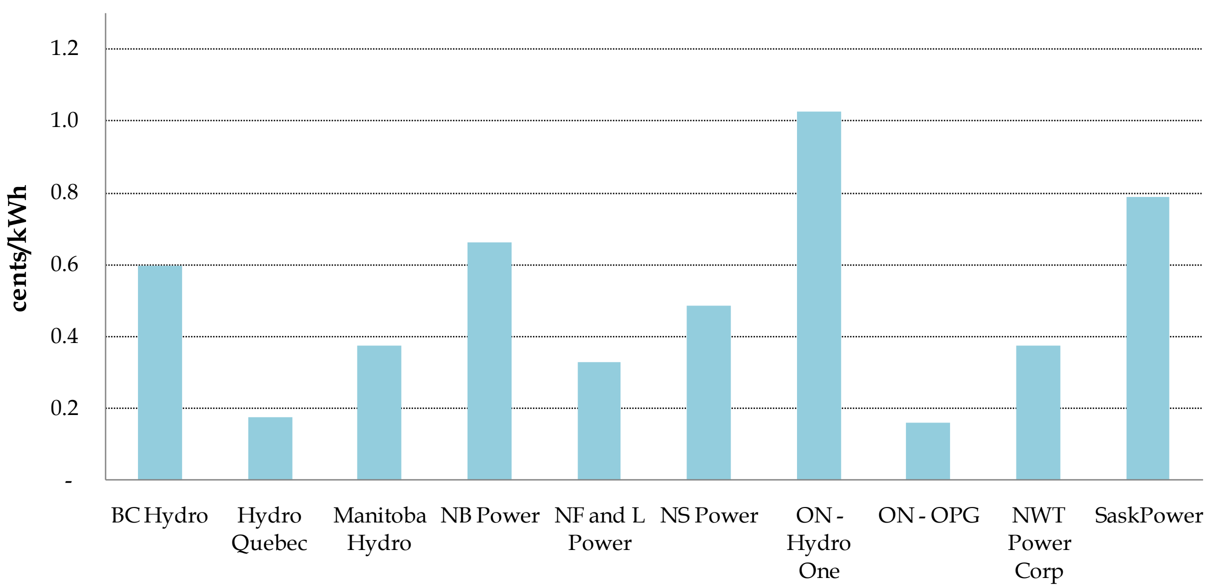
Figure 8. Debt as a portion of assets for selected provincially-owned utilities, 2009



Source: Annual reports

Note: debt is calculated as total assets minus total shareholder equity.[20]

Figure 9. Extent to which implicit debt guarantees suppress rates to final consumers



Source: Annual reports

[20] The average private regulated North American utility has approximately 50% debt based on a London Economics International LLC survey of 27 rate filings during 2009 for private electric utilities.

If provincial utility debt were consolidated onto provincial balance sheets, the impact would not be trivial. As the table below shows, the addition of utility debt to provincial debt loads increases provincial debt by a range of 16% to 46%.

Figure 10. Provincially-owned utilities' debt levels relative to overall provincial debt

Provincially-owned Utility	Utility debt (C$ billions)	Debt as a percentage of the utility's assets	Provincial debt (C$ billions)	Provincial debt plus implicit guarantee (C$ billions)	Utility debt as a percentage of provincial & implicit guarantee debt	Combined utility and provincial debt to gross provincial product
British Columbia Hydro	9.9	86.7%	32.8	42.6	23.2%	21.5%
Hydro Quebec	36.8	67.5%	160.1	196.9	18.7%	65.2%
Manitoba Hydro	7.8	83.5%	16.0	23.8	32.9%	46.9%
New Brunswick Power	4.3	92.5%	8.4	12.7	34.0%	46.5%
Newfoundland and Labrador Hydro	1.5	56.6%	7.9	9.4	15.9%	30.1%
Ontario*	62.6	NM	193.6	256.2	24.4%	43.6%
Qulliq Energy Corp (Nunavut)	0.1	72.2%	0.2	0.3	45.3%	17.4%
SaskPower	3.3	67.0%	3.9	7.2	46.0%	11.4%

Source: Annual reports, Statistics Canada, Toronto-Dominion Bank Financial Group

** Ontario debt includes Ontario Power Generation, Hydro One, and Ontario Electricity Financial Corporation*

This additional debt burden is not without cost for provinces. Although rating agencies have generally found that the combined debt burden is manageable for provinces, these agencies nonetheless do take the utility debt burden into account. Some examples of this fact are presented in Figure 11. In cases where the utility is performing poorly, the province's ability to raise funds for other activities may become strained. Furthermore, the capital that is locked up in a provincially-owned utility is not being invested in activities which may have a higher social return, such as health and education. In the meantime, because electricity rates are suppressed, consumption may be higher than is economically efficient. These distortions do not occur under the competitive market design in Alberta.

3.3 Suppressed equity returns

In addition to the distortion of debt costs caused by the halo effect, provincial shareholders fail to demand an appropriate return on equity from their utilities. By not demanding an appropriate equity return, the provincial shareholder is effectively failing to collect revenues from the electricity sector which could be used to fund social investments with far higher returns, such as investments in education, health, and regional development. Even though Canadian allowed returns on equity are generally lower than in the US,[21] Canadian utilities on average over the past five years have not achieved their allowed returns. As Figure 12 demonstrates, the realized returns on equity of all utilities are less than allowed rate of return

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[21] Regulated North American utilities have an allowed return on equity of 8.35% to 12%, based on a *Public Utilities Fortnightly* survey of 61 utilities in 2009.

by the regulators, which suggests utilities have not been seeking the rate increases needed to protect shareholders' (taxpayers') rights to a fair return.

Ontario provides several examples of this phenomenon. OPG's return on equity was held at 5% from 2002 to 2008. By foregoing a more competitive return on equity, the provincial government artificially depresses electricity rates.[22] In addition, recently, the Minister of Energy for Ontario has asked both Hydro One and OPG to to scale back their requests for rate increases for 2011-12.[23]

Figure 11. Rating agencies take the utility debt burden into account

Province	Description
Manitoba	Moody's considers the financial strength of Manitoba Hydro in meeting debt obligations when looking at Manitoba's credit rating.
New Brunswick	The rating agencies compare NB Power to other crown utilities in terms of how the corporation manages its finances. "If the corporation were not a viable, self-sustaining business, the rating agencies would consider the utility's debt to be supported by taxpayers and more of an imposition on the province's own credit."
Ontario	Standard and Poor's mentions in the credit analysis of Hydro One that the province's ownership enhances the utility's credit quality. "Although the province does not formally guarantee Hydro One's debt obligations, the strategic nature of the company within the provincial economy and the government's demonstrated willingness to financially assist the business under extraordinary circumstances in the past bode well for future support."
Quebec	One of the key rationales for Fitch's AA credit rating of "Hydro Quebec is the unconditional and irrevocable guarantee by the provincial government of Quebec."

Source: Credit rating reports from Moody's, Standard and Poor, Fitch, and DBRS

3.4 Differences in tax regimes

Provincially owned utilities also face a lower effective tax burden than do privately owned ones. As the chart below shows, over the past five years the average effective tax rate for Alberta utilities was 28%, while the effective average tax rate over the same period for provincially-owned utilities fluctuated between 6% and 24%. Additionally, we can see from Figure 15 that provinces with provincial utilities have higher corporate tax rates. Alberta has the lowest corporate tax rate in Canada of 10%.

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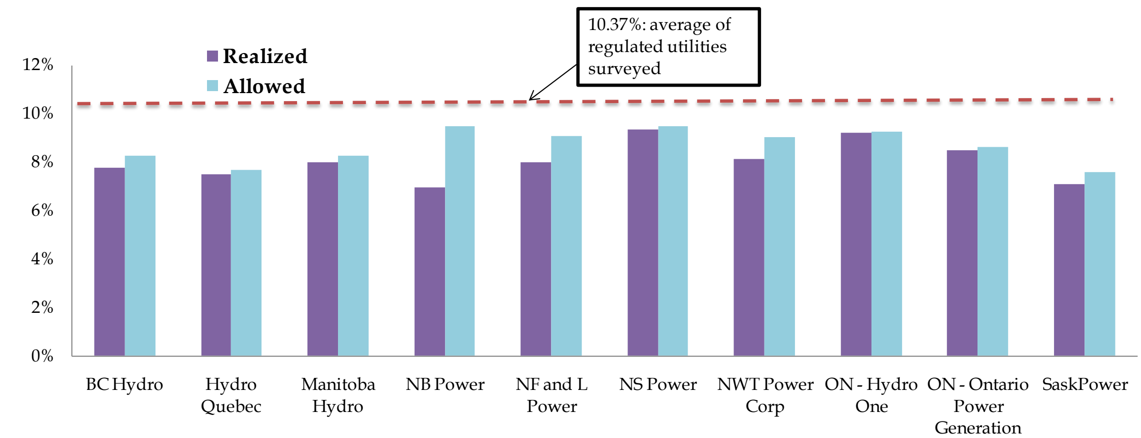
[22] Ontario Clean Air Alliance Research Inc. "Eliminating Subsidies and Moving to Full Cost Electricity Pricing". February 19, 2008. Page 9.

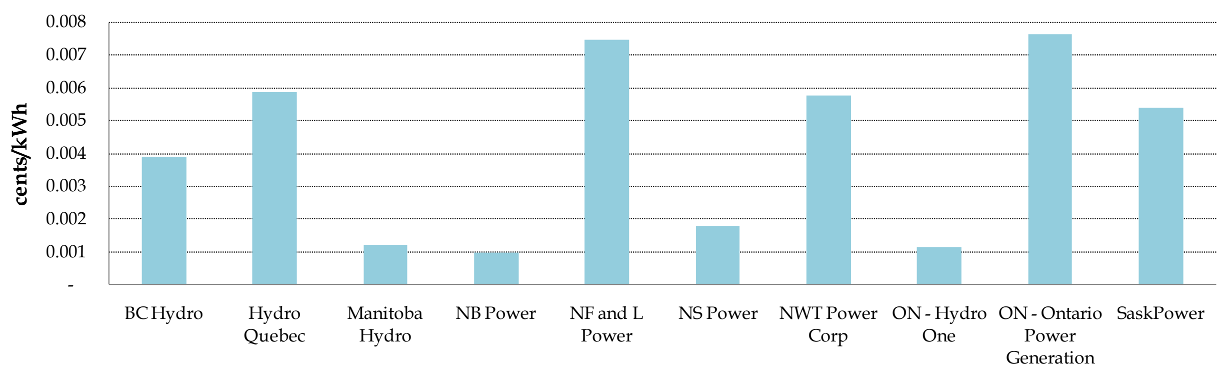
[23] *The Globe and Mail*. "Ontario energy regulator blamed for sharp rise in hydro bills". September 24, 2010.

Figure 12. Average allowed versus realized return on equity for utilities across Canada, 2005-09



Source: Utilities annual reports, Regulators

Figure 13. Extent to which regulated returns on equity suppress rates to final consumers



Lower effective tax rates reflect a direct subsidy from tax payers to rate payers. Equalizing tax rates with Alberta results in an additional adjustment to rates. To determine the impact, we calculate the amount of tax that each utility would have paid were it paying taxes at an effective tax rate of 28%, the Alberta prevailing rate. Were the higher statutory rate in other provinces to be used, the corresponding rate impact would be higher. The table below shows approximately how much would be added to rates in each province. The increase for residential customers ranges from 1% to 9% and the increase for industrial customers ranges from 1% to 17%. While many factors contribute to Alberta's low tax levels on corporations and businesses, these low tax levels are correlated with Alberta utilities paying a full share of their tax burden; taxpayers in Alberta are not subsidizing electricity ratepayers.

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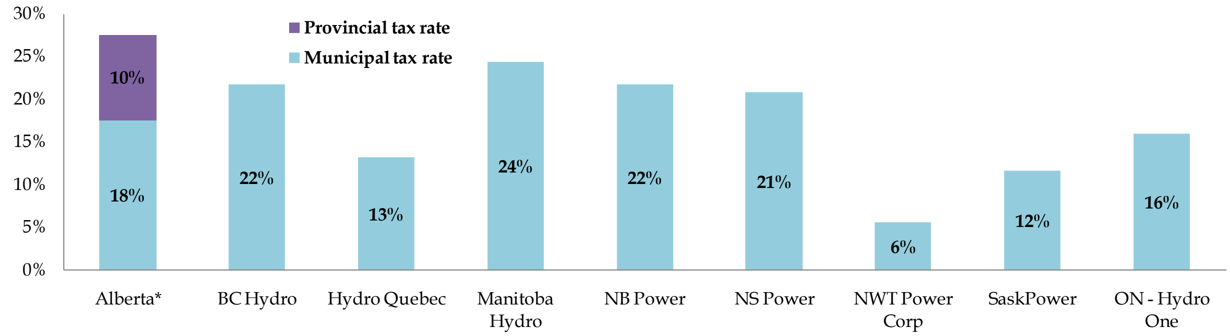
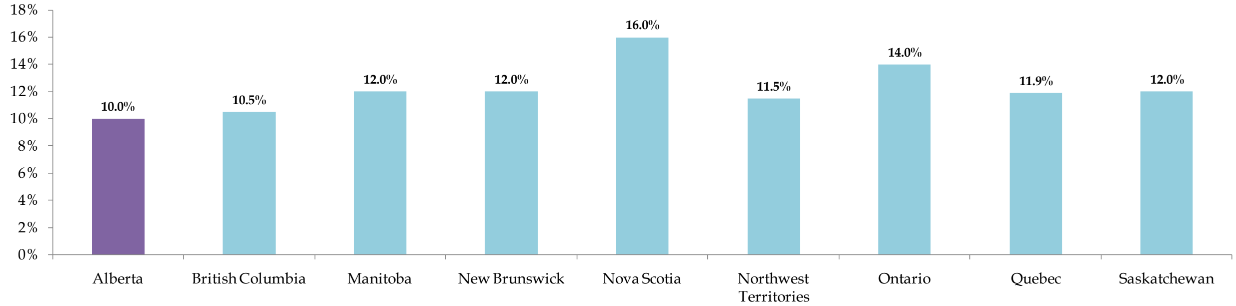
Figure 14. Tax analysis across Canadian utilities



Source: Utilities annual reports

Note: Effective tax rates are calculated as the ratio of tax expense to operating income, average of past five years

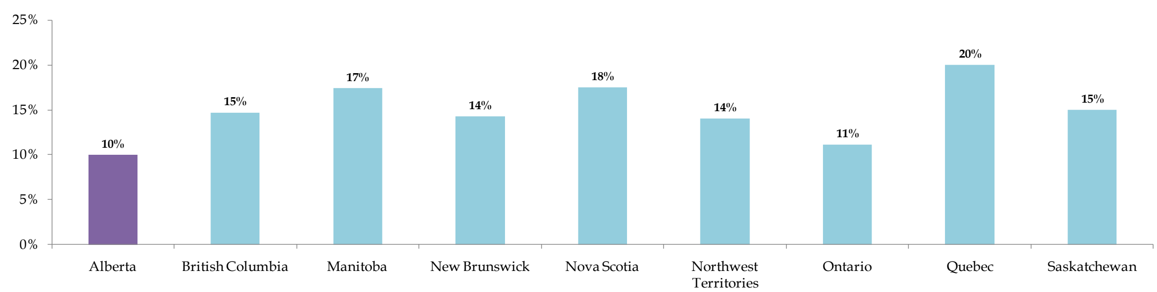
Figure 15. Provincial tax rates for corporations are lowest in Alberta



Source: Canada Revenue Agency, Government of Alberta; as of 2010

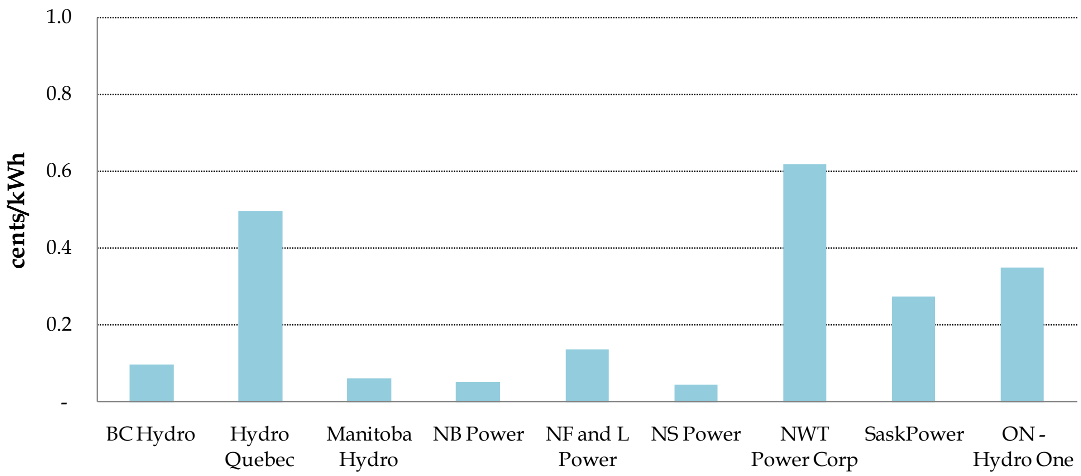
Note: Federal tax rate is 18% for corporations.

Figure 16. Personal income tax rate for highest taxable income bracket



Source: Canada Revenue Agency, Government of Alberta; as of 2010

Figure 17. Addition to final rates assuming effective tax rates in Alberta



Source: Utilities annual reports

3.5 Impact of heritage contracts and export revenues

Rates can be distorted by other factors as well. Two such factors are heritage contracts and export revenues. In effect, heritage contracts and export revenue adjustments are other means to quantify the impact of differing resource endowments and the benefits of large scale hydro. Heritage contracts provide power to consumers at embedded cost rates; these embedded cost rates are often (though not always) below the opportunity cost of what the power could be sold for within an organized power market. The difference between the heritage contract price and the market price represents a transfer from shareholders (in this case, taxpayers) to ratepayers, and the resulting lower delivered power prices in potentially inefficient consumption patterns. Similarly, most large exporting provinces use export revenues to reduce rates within the province. Again, this reduces delivered power prices below the full value and ultimately skews consumption decisions. As with heritage contracts, this represents a transfer from taxpayer-owners to consumers, not all of whom are taxpayers. We describe these impacts in greater detail below.

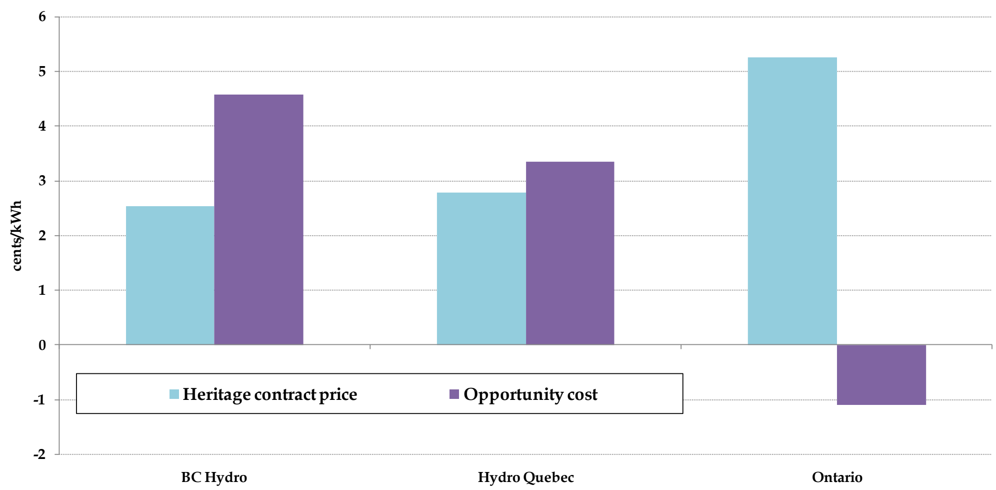
3.5.1 Heritage contracts

To calculate the rate impact of heritage contracts, we examine the amount of power associated with the heritage contracts and the price. BC, Quebec, and Ontario all have some form of heritage contracts.[24] In 2009, the heritage pool in BC was 49 TWh at 2.53 cents/kWh, while the

[24] In Alberta, the distribution of residual benefits from the PPA auctions through the Balancing Pool in some ways served the function of a heritage contract.

Hydro Quebec heritage pool was 165 TWh at 2.79 cents/kWh. In Ontario, the price for the "prescribed assets" of OPG serves as a heritage pool; the volume was 66 TWh and the price was 5.25 cents/kWh.[25] The next step is to determine the market price for this power based on the most appropriate nearby liquid market hub. For BC Hydro, we use the California-Oregon Border (COB) price; for Ontario, the HOEP; and for Hydro Quebec, we use the Massachusetts Hub price. We then derive the opportunity cost by determining the difference between the heritage contract price and the relevant market price. Because the heritage contracts do not fully cover domestic demand (heritage contracts accounted for 98% of 2009 consumption in BC, 99% in Quebec, and 48% in Ontario) we multiply the opportunity cost by the heritage contract volumes, and then divide by total domestic volumes to determine the average impact of the heritage contracts on rates. The results of these calculations are summarized in Figure 18. In 2009, the opportunity cost of heritage contracts in BC and Quebec were positive, but in Ontario they were negative, indicating that the heritage contracts in Ontario imposed higher costs on consumers.

Figure 18. Impact of heritage contracts on final rates for consumers, 2009



Source: Utilities annual reports

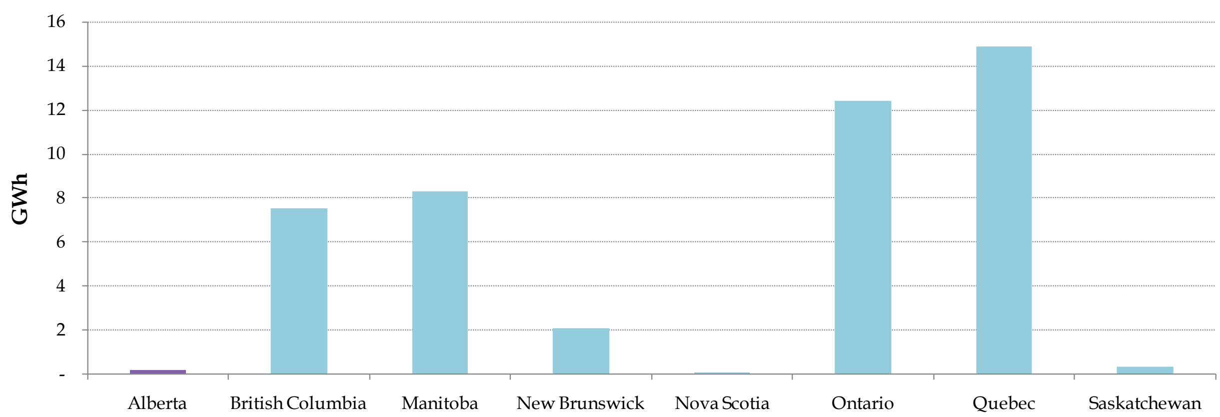
Note: A positive opportunity cost means that the heritage costs allow customers to pay less than the current market value of the power. By contrast, a negative opportunity cost means customers are paying more than the current market value for power.

[25] In 2009, the price for OPG's regulated nuclear and hydroelectric assets were 5.82 cents/kWh and 3.9 cents/kWh. Amount generated during the same period were 46.8 TWh and 19.4 TWh for regulated nuclear and hydroelectric assets (respectively). The weighted average price for OPG's regulated assets comes to 5.25 cents/kWh. Source: Ontario Energy Board. Order number EB-2007-0905. <http://www.rds.oeb.gov.on.ca/webdrawer/webdrawer.dll/webdrawer/rec/93959/view/payment_order_OPG_20081202.PDF>, pg. 4-6. OPG. *2009 Annual Report.* <http://www.opg.com/pdf/Annual%20Reports/Annual%20Report%202009.pdf>

3.5.2 Treatment of export revenues

In the provinces with the largest exports, export revenues are generally used to reduce rates. This can lead to some adverse impacts: for example, as wholesale generation prices in export markets fall in response to a slow economy, Canadian utilities may be forced to increase rates to cover the shortfall in export revenues. Proposed rate increases for BC in 2011 are partly based on this fact.

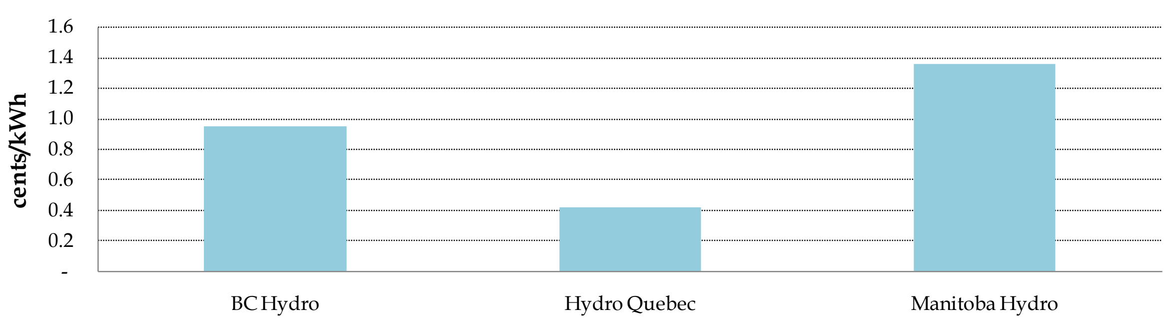
Figure 19. Average annual electricity exports by province, 2005-09



Source: Statistics Canada

Over the past five years, on average, export revenues may have decreased rates by 0.95 cents/kWh in BC, 1.36 cents/kWh in Manitoba, and 0.42 cents/kWh in Quebec.

Figure 20. Average annual export revenue effect on rates to final consumers



Source: National Energy Board, Utilities annual reports, LEI calculations

Figure 21. Treatment of export revenues by selected utilities

Company	Treatment of export revenues
British Columbia Hydro	Export revenues are taken into account in the design of customers' rates. For instance, the 2011 increase request was partly justified by lower than expected trade revenues.
Hydro Quebec	Hydro-Québec Distribution and Hydro-Québec TransÉnergie include revenues earned from electricity exports in their respective costs of service as negative costs thus reducing rates. Hydro-Québec Production (HQP), is not subject to regulation; HQP revenues earned from electricity exports increase dividend payments made to its ultimate shareholder, the Government of Québec.
Manitoba Hydro	Export sales are used to offset construction costs and to help keep electricity rates low in the province. The company will launch new infrastructure investments only once new export sales contracts are secured, in order to ensure a minimum return on investment.

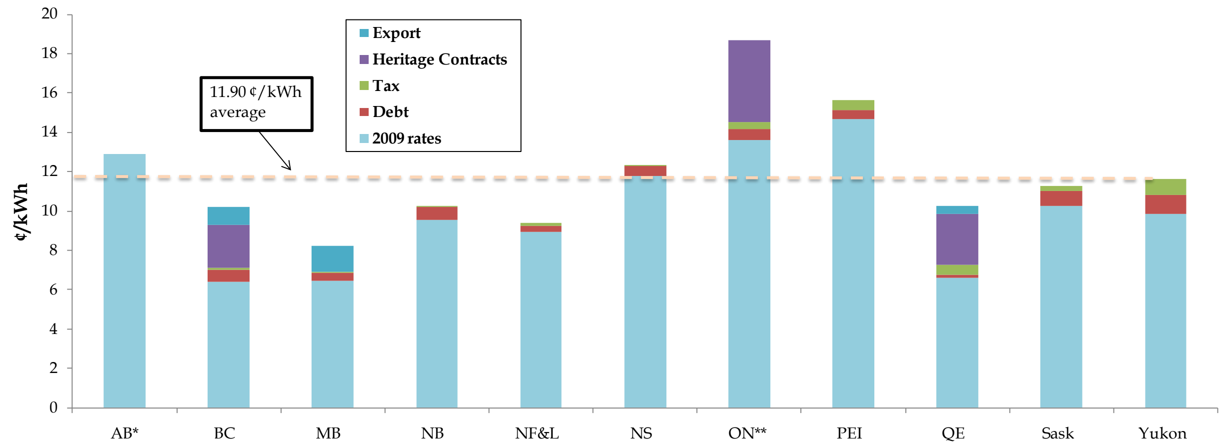
Source: BC Hydro. Annual Report 2009. Financial Statements. <http://www.bchydro.com/about/company_information/reports/annual_report.html>, pgs 56-59. Manitoba Hydro. Annual Report 2009. Financial Statements. <http://www.hydro.mb.ca/corporate/financial.shtml?WT.mc_id=2112>, pgs 23 and 67. Hydro Quebec. Annual Report 2009. Financial Statements. <http://www.hydroquebec.com/publications/en/annual_report/index.html>, pg. 7.

3.6 Combined effect of adjustments

When the various distortions that arise from provincial ownership are taken into account, Alberta's rates are, overall, competitive with most of its peers across Canada. To determine the full cost of power across Canadian provinces, we examine the combined impact of the distortions we describe above. This means for each province adding together the 2009 actual rates, the adjustment to correct for over-leverage, the adjustment for differing tax regimes, and the impact of heritage contracts and export sales. When the combined impact of these effects is taken into account, Alberta rates are more competitive across Canada.

Alberta's competitive position becomes even stronger when the 2010 rate increases are factored in, as shown in Figure 22 and Figure 23 for residential and industrial customers respectively.

Figure 22. Rates for residential customers adjusting for various distortions, 2009



Note: To derive adjusted retail rates for heritage contracts, we removed the revenue premium paid to heritage assets from total system-wide revenues. When heritage assets receive lower revenues than they would have if they received market prices, the difference is added to total system-wide revenues.

Figure 23. Rates for industrial customers adjusting for various distortions, 2009

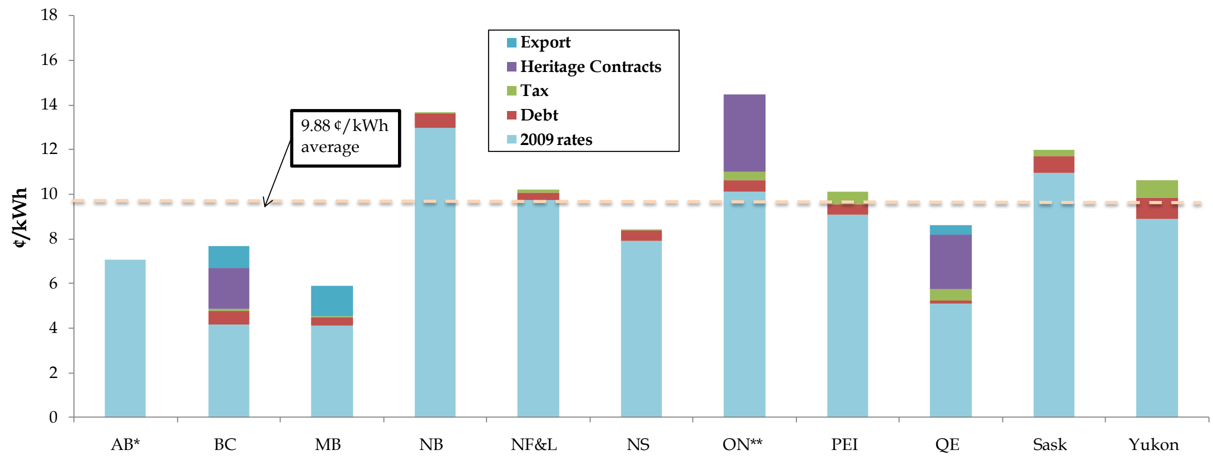


Figure 24. Adjusted rates for residential customers including 2010 announced rate increases

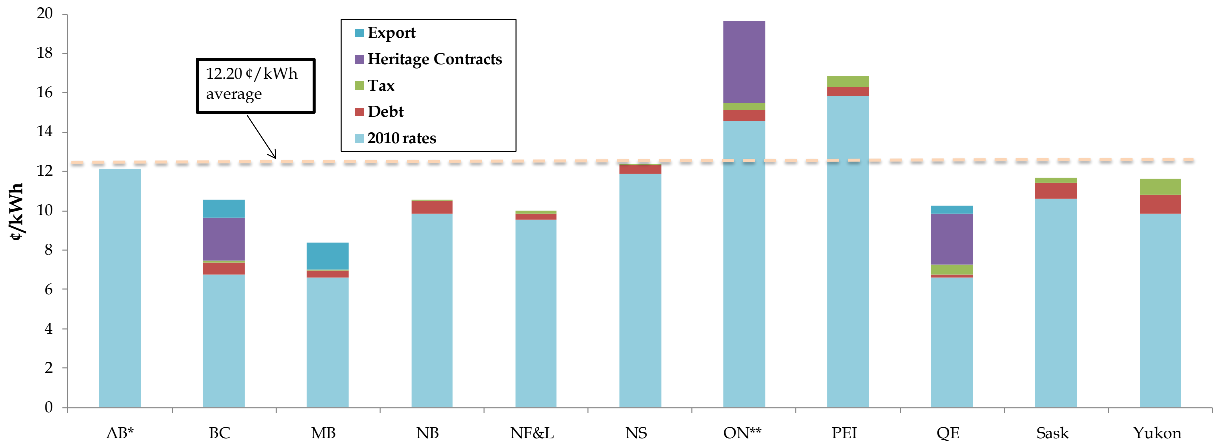
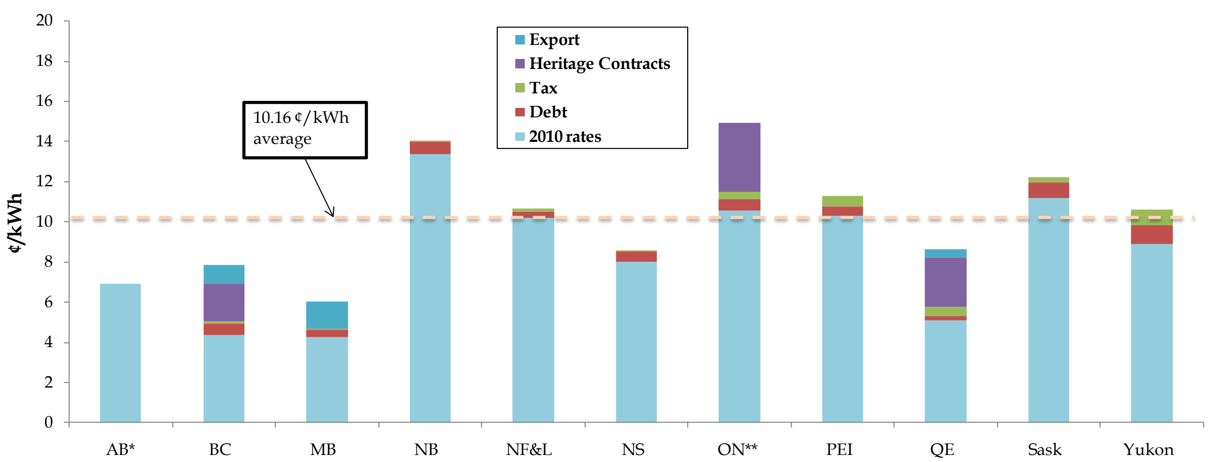


Figure 25. Adjusted rates for industrial customers including 2010 announced rate increases



4 Rate outlook for next five years

Rates to final consumers consist of a number of elements, primarily grouped first around the cost of generation and second around the cost of delivery (transmission and distribution). While analysis suggests that wholesale generation costs in Alberta over the next five years will remain moderate, rates to final consumers may rise due to the extent of projected capital expenditures.

This section provides an overview of the methodology and assumptions used in developing an outlook for the residential and industrial rates in Alberta for the next five years. This involves three key steps: first, developing an outlook for wholesale market prices in Alberta using our proprietary model; second, developing an outlook for the increase in distribution and transmission tariffs from new capital expenditure in Alberta; third, the sum of these components produces the expected delivered price. To determine the generation component, we develop an outlook for wholesale prices, based on assumptions regarding market topology, fuel price projections, emission costs, demand, supply, and new entry.

In order to calculate the evolving cost of energy delivery in Alberta:

- We created composite residential and industrial Alberta delivery charges based on the current customer-weighted average rate to residential and industrial customers for major utilities. The utilities meet approximately 87% of total load in Alberta.

- We then determined the level of future capital expenditures in transmission and distribution across Alberta, estimated the current regulated asset base (RAB) and total revenue requirement across Alberta, and identified changes to the RAB and total revenue requirement as a result of the new capital expenditure projects.

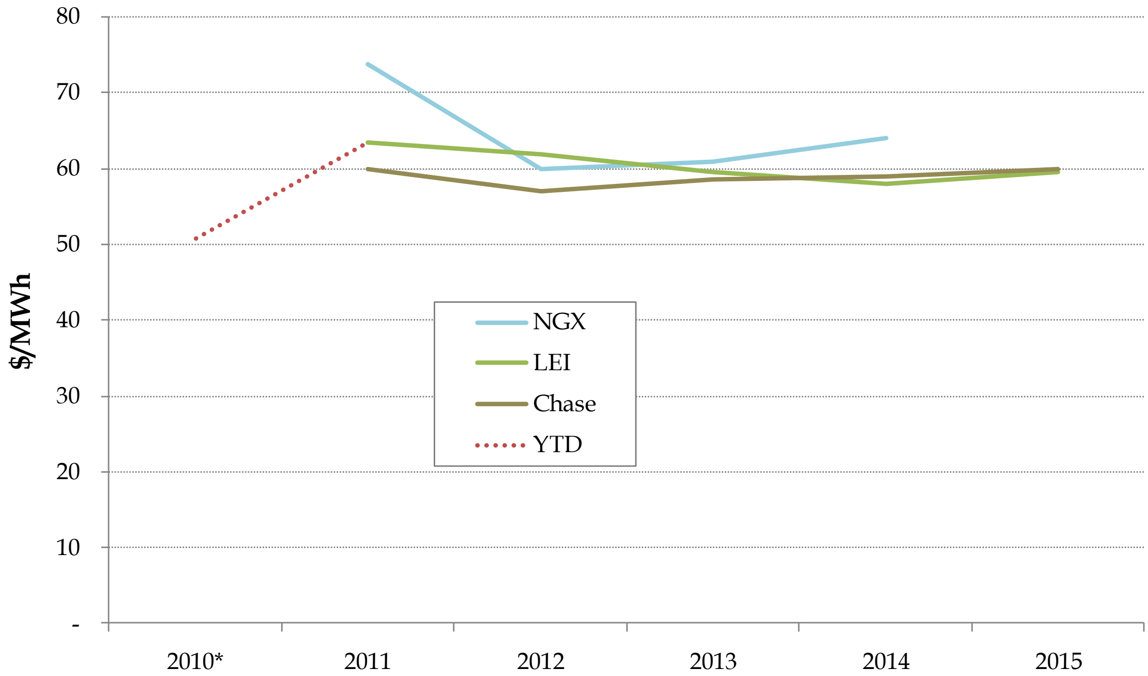
- We next appropriately divided changes in the total revenue requirement amongst residential, industrial and other customers to estimate the change in the distribution and transmission component of rates.

It is important to emphasize that ***the analysis presented here is simplified and indicative.*** Projected rates shown here are generic; utility specific rates will vary. Future rates are dependent both on the timing of new capital expenditures and the treatment of such capital expenditures in rates. Wholesale generation prices are affected by levels of projected demand, fossil fuel costs, and new entry. Detailed comprehensive scenario analysis of all of these elements was beyond the scope of this engagement. Nonetheless, while other outcomes are possible, we believe the underlying conclusions are sound: the key drivers of rate increases in Alberta over the next five years will be the timing and magnitude of investments in transmission and distribution, rather than wholesale generation prices.

4.1 Developing an outlook for wholesale generation prices

LEI's outlook for wholesale generation prices ranges from $66.38 per MWh in 2011 to $61.62 per MWh in 2015. This compares with an average price of $47.81 per MWh in 2009 and an average of $50.88 per MWh in 2010.[26] As the chart below demonstrates, LEI projections, as of February 2011, are also consistent with current forwards.

Figure 26. LEI outlook for prices are consistent with forwards, 2011-15



Source: AESO, Natural Gas Exchange (NGX). Accessed at 3 pm, February 17, 2011. "http://www.ngx.com/marketdata/settlements/AFSETTLE.html". Chase Energy Canada Limited. February 10, 2010. "Power Fundamental Report for the Alberta Energy Industry".

**As of December 2010*

Note: between 2011-14, there are natural gas, hydro and wind power plants projected to come online that slightly reduce the market prices in LEI modeling.

[26] Prices reflect the retirement by TransAlta of two coal-fired units at the Sundance power station in December 2010.

Figure 27. Assumptions for 5 year wholesale price outlook for Alberta, 2011-15

Demand	• Based on load forecast results published in AESO's 2010 Future Demand and Energy Outlook
Emission Costs	• Developed an outlook using 2009 weighted average of $15/ton CCEMC fund contribution and offset costs of $9-13/ton in 2009 and the 2009 utilization ratio between fund and offsets
Fuel Prices	• Natural Gas price assumptions are based on natural gas futures provided by NYMEX (HH) and NGX (AB-NIT) • Coal prices are based on actual plant-based delivered coal prices and escalated in line with inflation
Market Topology	• Alberta's market is modeled as one zone with current interties to British Columbia and Saskatchewan
New Entry	• New entry assumptions are derived from the AESO generation connection queue and industry research • Costs of generic new entry are derived using LEI's proprietary New Entry Trigger Price (NETP) Model

Alberta's market is modeled as one zone with current interties to British Columbia and Saskatchewan. Alberta is assumed to be a net importer from its neighbors. Demand (MW) grows at 2.2% per annum in accordance with the historical rate of growth from 2005 to 2009. Generic plants are assumed to enter the market when price levels signal that it is economic for them to do so. Natural gas price assumptions are based on NYMEX Henry Hub futures for 2011-15, adjusted for the historical differential between NGX AECO forwards[27] and Henry Hub prices over the last five and a half years, from 2005-10.[28]

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[27] NGX-AECO stands for the National Gas Exchange Inc.'s Alberta Energy Company's Nova Industry Transfer (NIT) storage and exchange point for natural gas in Alberta. For more information, see <http://www.ngx.com>.

[28] For more information, see <http://www.eia.doe.gov/oiaf/aeo>.

Figure 28. Demand and supply outlook, 2011-15

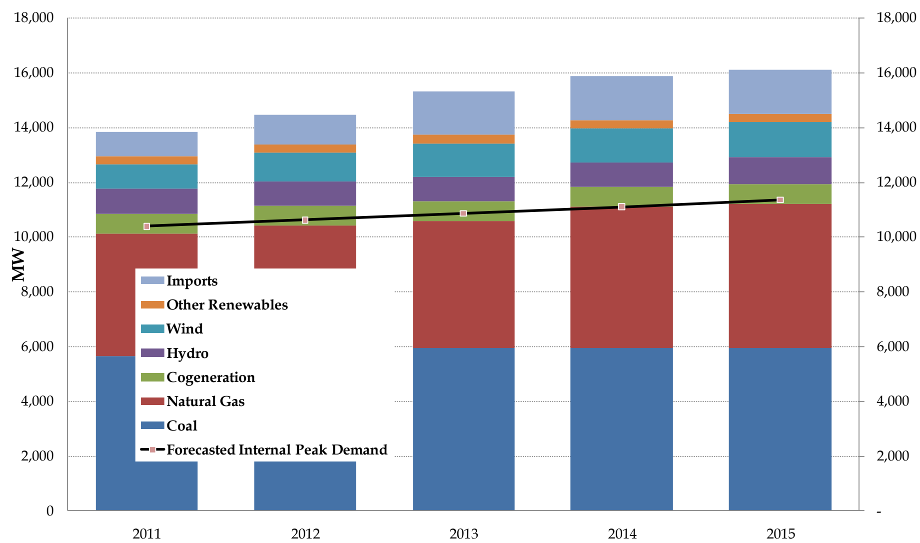
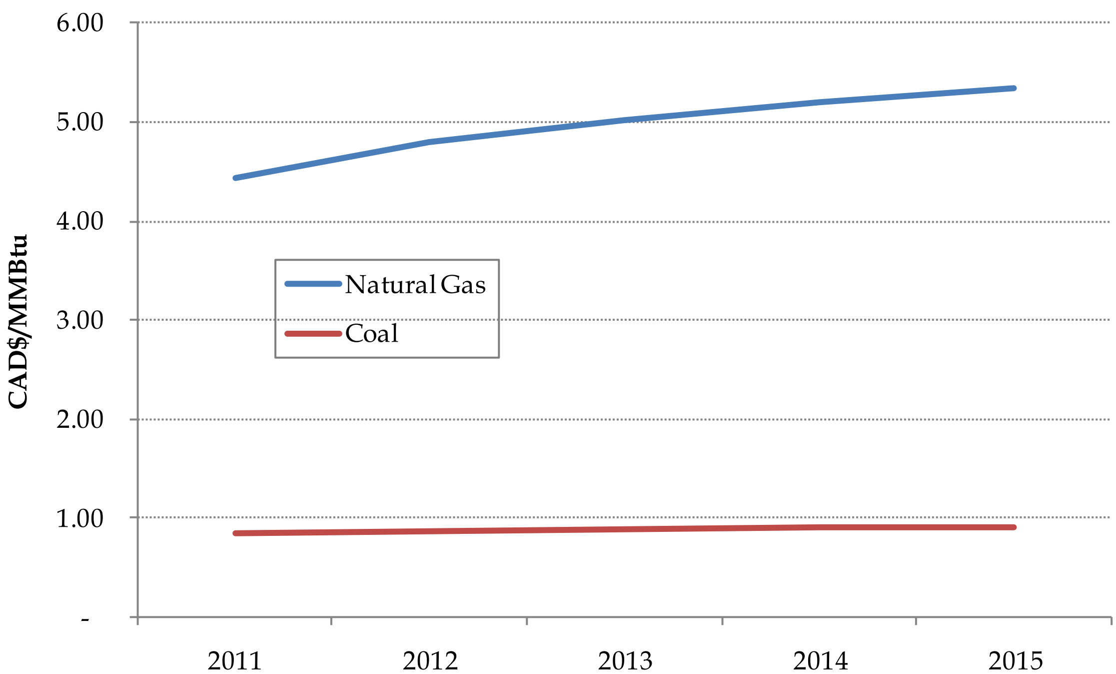


Figure 29. Fuel price assumptions, 2011-15



4.2 Determining delivery charges

Figure 30. Steps for calculating five year price outlook for wires components

1. Estimate the current regulated asset base (RAB)
2. Estimate the total revenue requirement based on existing asset base
3. Determine the level of future capital expenditures in transmission and distribution
4. Estimate changes to operating and depreciation expenses as the result of the new capital expenditure
5. Estimate changes to the RAB and total revenue requirement as a result of the new capital expenditure minus the depreciation on existing assets
6. Allocate the changes in the total revenue requirement between customer classes
7. Estimate the change in the distribution and transmission component of rates

To estimate future wires charges, we create a simplified model of transmission and distribution rates. The process starts with calculating the current transmission and distribution regulated asset base (RAB) for four major utilities in Alberta.[29] Currently, the size of distribution and transmission RAB are approximately $3.6 billion and $2.8 billion respectively. This data was obtained from the latest rate filing of utilities with Alberta Utilities Commission (AUC).

The next step is to calculate the current revenue requirement. The annual revenue requirement includes the summation of the allowed return on invested capital (weighted average cost of capital multiplied by the rate base) and operating expenditures. Expenses are the ongoing costs of operating and maintaining the service provider's equipment, which include salaries and

[29] The four major utilities are ENMAX, EPCOR, FortisAlberta, and ATCO.

related labor costs, general and administrative expenditures, materials and supplies, and electricity generation and fuel costs. Depreciation is also included as an expense to arrive at the total revenue requirement.

New capital expenditures to be incurred in each subsequent year also form a key part of the RAB. The rate base will increase by the amount of new investment placed in service over the previous year, and decrease by the amount of depreciation. In Alberta, over the next five years, more than $10 billion has been allocated for transmission and distribution projects. Figure 31 shows the list of transmission projects included in the model. Figure 32 shows projected distribution capital expenditure by utility.[30]

Figure 31. List of expected transmission projects in Alberta, 2011-15

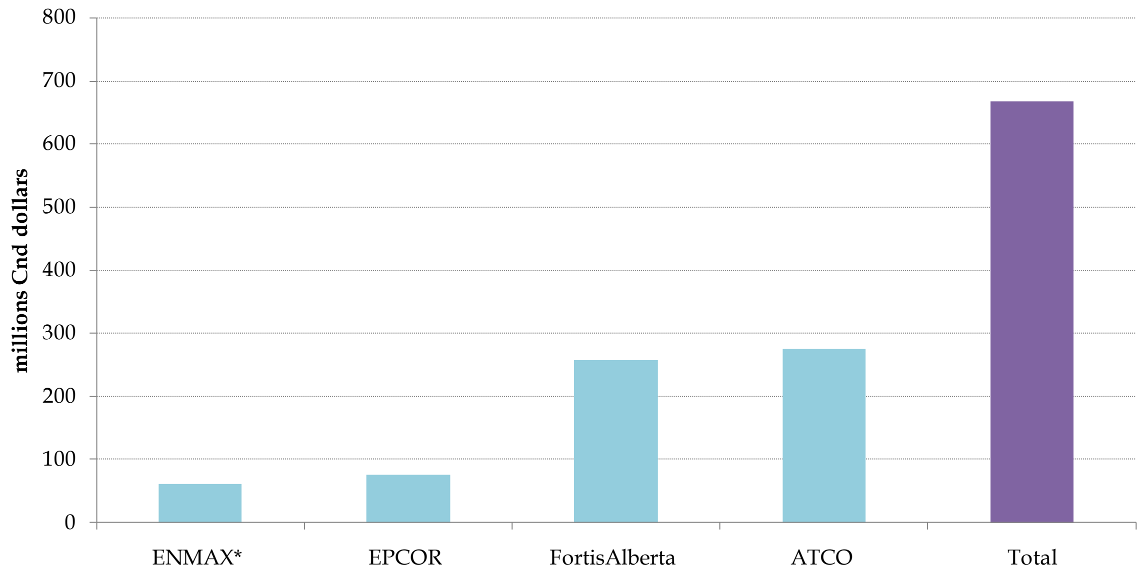
Name of project	Total (millions)		Date in service
9L66 240kV Line Relocation	C$	1.2	2011
North Central Region Transmission Development	C$	51.8	2013
Calgary Business District	C$	62.4	2011
South East Transmission Reinforcement	C$	74.5	2011
Yellowhead Area Transmission Development	C$	87.8	2012
ENMAX No. 65 Substation	C$	110.0	2012
Edmonton Region 240kV Line Upgrades	C$	125.4	2012
North West Transmission Development	C$	262.5	2012
Hanna Region Transmission Development	C$	848.7	2013
Southern Alberta Transmission Reinforcement	C$	1,808.0	2015
North South Transmission Reinforcement	C$	2,390.0	2014
Alberta Industrial Heartland Bulk Transmission Development	C$	3,013.2	2013
Total	**C$**	**8,835.5**	

Source: Alberta Electric System Operator, "http://www.aeso.ca/downloads/2010_Q4_Tx_System_Quarterly_Report_R1.pdf". 2010 Q4 report.

Note: only projects that are approved and expected to be completed between 2011-15 are included. The following projects, approximately C$747 million, were not included from the Q4 report as they are pending approval of AUC: Athabasca Area Upgrade, North East Voltage Support, ENMAX South 69kV Conversion, Livock 240/144kV Reinforcement Project, Long Range Airdrie Area System Development, Ft McMurray Area 144 kV Reinforcement, Pincher Creek Area 240/138 kV Transmission Development, North Ft McMurrary Transmission Development, and Central East Area Transmission Development. For full cost of Alberta Industrial Heartland project, refer to "Heartland 500 kV Transmission Project" report issued by AltaLink and EPCOR in September 2010.

[30] While our simplified rates model assumes common treatment for capital expenditure amongst all distribution companies, in fact treatment of capital expenditure in rates currently varies. Future treatment of capital expenditure will depend on the outcome of ongoing rate design proceedings before the Alberta Utility Commission.

Figure 32. Distribution capital expenditure, 2010-11



Note: Impact of distribution capital expenditure differs depending on utility and associated rate design. Distribution operating expenses and depreciation are added separately to revenue requirement.

These assets will begin to depreciate as soon as they come into service. The depreciation rates for transmission assets are determined based on AUC-accepted depreciation rates from current tariff filings for utilities in Alberta.[31] Depreciation rates for distribution assets are also based on AUC-accepted rates from current tariff filings for utilities in Alberta.[32] Furthermore, we calculate the addition to the operating expenses as the result of the new capital expenditures using the current ratios of operating expenses to total RAB for all four major utilities.

Distribution capital expenditures are obtained from recent rate filings of the major utilities with AUC as shown in Figure 32. Major components of these expenditures include capital maintenance and upgrades. Distribution capex is normally provided for the following two years. The historical growth rate of distribution capex for each utility is used to extend the outlook until 2015.

The treatment of plant, property and equipment that is in the process of being constructed and has not yet been entered into service can affect cash flows to the utility. The key issue in the regulatory treatment of this cost component is timing, specifically when the work in process is

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[31] These rates vary from 34 to 37 years according to AUC filings for AltaLink and ENMAX. AltaLink *General Tariff Application*, 2009-2010. Page 99. Source: ENMAX. *Formula Based Ratemaking, 2007-2016*. Page 75.

[32] These rates vary from 27 to 31 years according to AUC filings for ATCO Electric and ENMAX. ATCO Electric *General Tariff Application, 2011-2012*, Schedule 16-3. Source: ENMAX. *Formula Based Ratemaking, 2007-2016*. Page 75

properly entered into the RAB. In our modeling, we use the allowance for funds used during construction (AFUDC) method, which is used predominantly across utilities in Alberta. Under AFDUC, no returns are provided on these assets until construction is completed. Instead, they are recorded in an accounting sense, with the value of the underlying investment increasing annually to reflect the accumulated returns. When the plant is placed into service, its cost (properly adjusted to reflect the value of all deferred returns) is then placed into the RAB.

Given the current consumption (kWh) by each customer class as a weight, we calculate the increase in residential and industrial rates over the next five years.[33] We add the outlook for wholesale energy prices and the current level of transmission and distribution charges to arrive at the final rates.

4.3 Impact on rates

To explore the impact on rates of various investment scenarios, we considered two scenarios: (i) investment as scheduled case and (ii) delayed investment scenario. In both cases we applied the LEI base case outlook for wholesale generation prices. However, in the "investment as scheduled" case, we assume that all proposed capital expenditures (regardless of whether this investment is transmission or distribution) are brought into service according to their announced schedule. In the "delayed investment" scenario, we assume that all planned capital expenditure is delayed by two years. While rates to final consumers increase in both cases, unsurprisingly, the magnitude is less when the proposed investment is delayed.

4.3.1 Residential rate outlook

Residential rates are projected to increase from 11.7 cents/kWh in 2011 to 13.1 cents/kWh in 2015, as shown in Figure 33. This is mainly accounted for by the cost increases for transmission and distribution; increases range from 0.11 cents/kWh in 2011 to 1.9 cents/kWh in 2015, with a significant portion due to additional transmission projects entering the rate base in 2014 and 2015. The Regulated Rate Option is expected to remain relatively flat throughout the period.

4.3.2 Industrial rate outlook

Industrial rates are projected to increase from 8.5 cents/kWh in 2011 to 9.8 cents/kWh in 2015, as shown in Figure 34. As with the residential rates, the increase is mainly accounted for by charges to transmission and distribution. Costs for new investment in transmission and distribution are anticipated to increase from 0.11 cents/kWh in 2011 to 1.9 cents/kWh in 2015, with a significant portion of this increase accountable due to additional transmission projects entering the rate base in 2014 and 2015. The wholesale energy charges, are projected using LEI's internal model, explained in Section 4.1. These rates remain relatively flat throughout the period.

[33] Note that this treatment assumes rates adjust in the year RAB adjusts; in fact, rate adjustments may lag due to filing schedules. While we recognize that some utilities are seeking to move to construction work in progress (CWIP) rather than AFUDC, our modeling uses AFDUC throughout. CWIP would cause the rate increase to occur somewhat earlier.

Figure 33. Residential customers price outlook, 2011-15

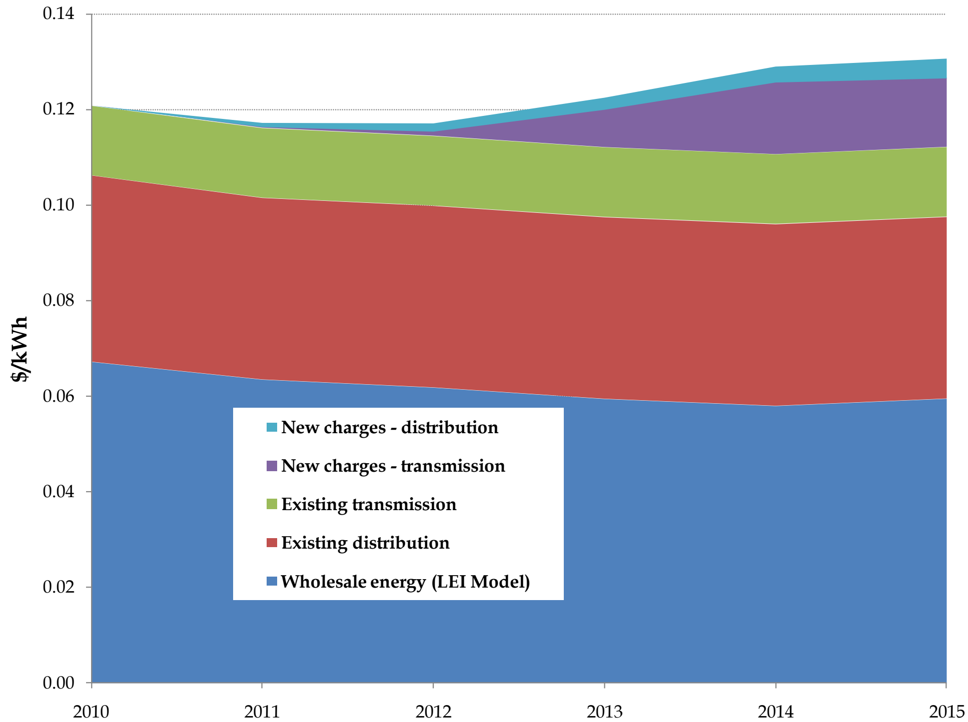
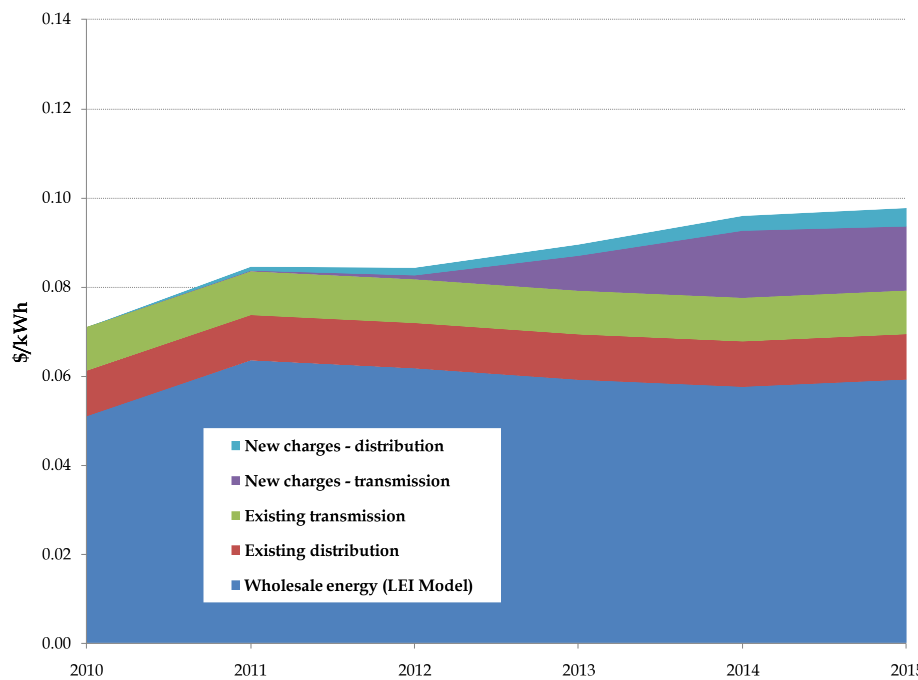


Figure 34. Industrial customers price outlook, 2011-15



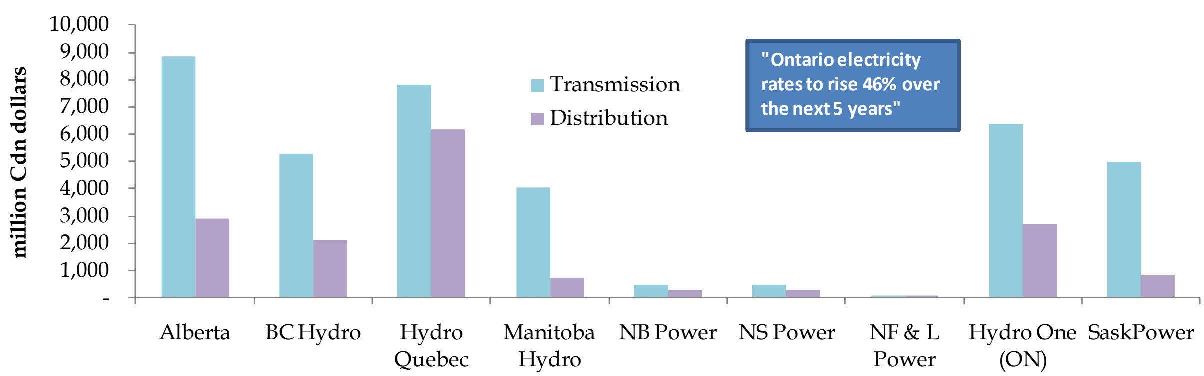
4.3.3 Collective impact

When we examine the scenarios broadly, we find that, under the current investment plan, expected transmission capital expenditure contributes 78% of the increase in rates, while distribution contributes the remainder. If all proposed capital expenditures are delayed by two years, the share of transmission in the rate increases is 44% and distribution is 56%. Considering the increase to the residential and industrial rates over the next five years and looking back at the rates adjusted for various distortions in Section 3.6, Alberta rates would become yet more competitive in Canada.

4.4 Prospects for other provinces

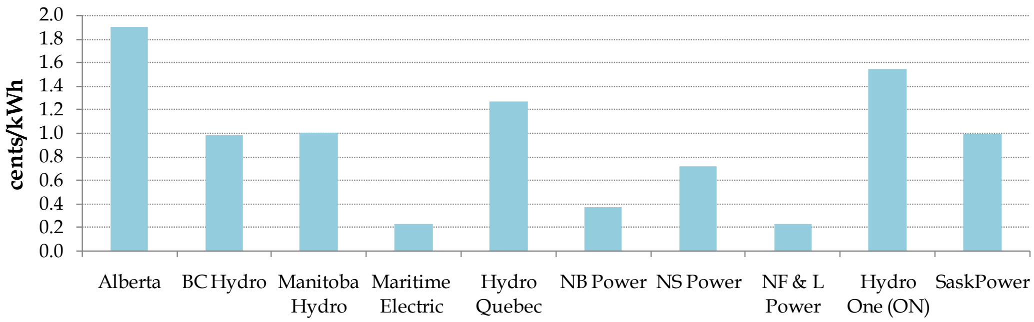
Other provinces also have aggressive wires infrastructure development programs. We created preliminary estimates for transmission and distribution capital expenditure and their impact on rates for other provinces in Canada. We use similar methodology to that adopted in Section 4 for Alberta. Planned transmission and distribution projects for the 2011 to 2015 period (as shown in Figure 36) are all included. We add these to the existing regulated asset base and apply the weighted average cost of capital that was previously used in the Alberta model. We use similar depreciation lives to what was used in the Alberta model to arrive at the additions to the revenue requirement. Then, using the current consumption level for each province as a divisor to the resulting revenue requirements, increasing at projected load growth rates, we calculate the increase in rates over the next five years. The main effect on rates is shown in Figure 37.

Figure 35. Transmission and distribution capital expenditure for other provinces, 2011-15



Source: Utilities annual reports, CBC. "Ont. electricity rates to rise 46% over 5 years". November 18, 2010. <http://www.cbc.ca/canada/toronto/story/2010/11/18/ontario-duncan-economic-update234.html>.

Figure 36. Expected rate increase from new capital expenditures



Note: only projects that are approved and expected to be completed between 2011-15 are included

Figure 37. Expected residential rates in 2015

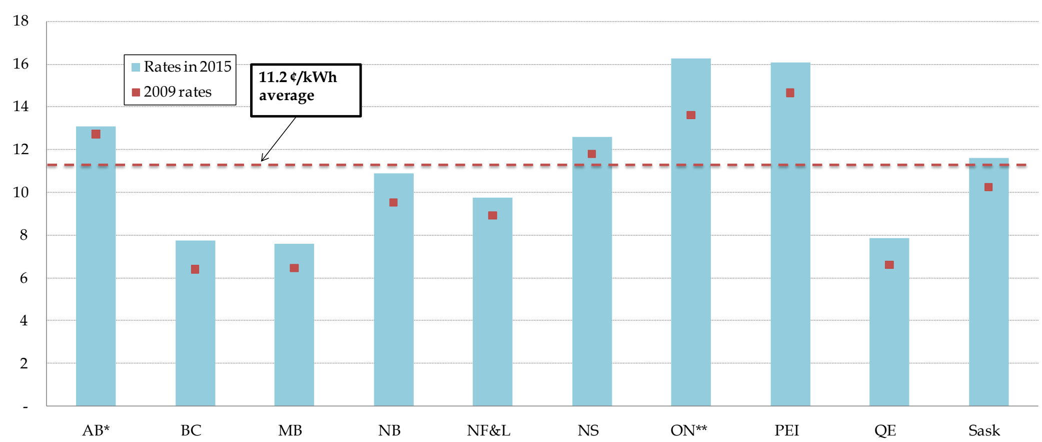
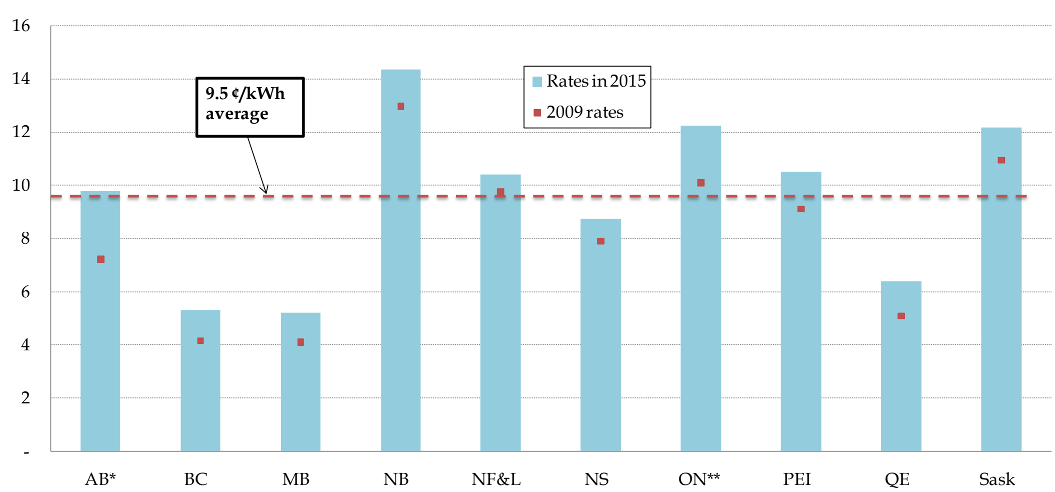


Figure 38. Expected industrial rates in 2015



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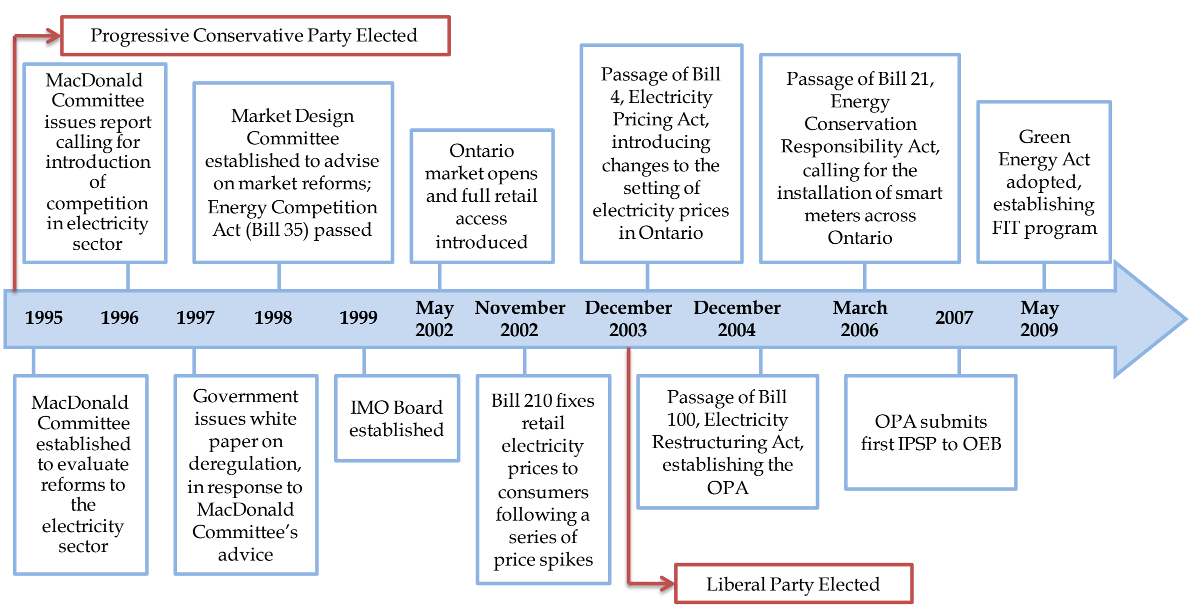
5 Lessons from Ontario

The Ontario electricity sector has faced a volatile policy environment over the past decade. While Alberta commenced the decade with a reconfiguration of market institutions and there have been a number of discussions about market design, policymakers have generally emphasized the centrality of the market to electricity sector development. By contrast, Ontario removed the word "market" from the name of its system operator and has largely replaced the role of the market in long term investment planning with a procurement authority. However, the abandonment of the market and the failure to allow the procurement authority to be independent in its planning have resulted in a power sector facing conflicting messages and consumers ultimately paying higher prices than would otherwise be necessary to achieve the stated policy goals.

5.1 Brief history

Although initially considered by the MacDonald Committee in 1995, liberalization of the Ontario power sector did not get under way until 1998 with the creation of the Ontario Market Design Committee (MDC). The MDC process took one year and ultimately resulted in a plan to break Ontario Hydro into several companies, including Ontario Power Generation (OPG) and wires company Hydro One. Market opening, though much delayed, ultimately took place in May 2002; less than six months later, following a hot summer and increased customer bills, prices were frozen to final consumers in November 2002.

Figure 39. Key developments in the Ontario electricity market



Following a change of administrations, the Ontario Power Authority (OPA) was created in December 2004. Initially the OPA was portrayed as a transitional procurement agency until supply challenges were addressed. Eight years later, the OPA is no longer regarded as

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temporary. The OPA commenced operations with a series of contracting rounds and the creation of an Integrated Power System Plan (IPSP) intended to provide a blueprint for future procurements.

Despite the successful completion of contracting sessions directly targeting renewables, the Ontario government nonetheless decided, by promulgating the Green Energy Act (GEA) on May 14, 2009, to implement a feed-in tariff (FIT) structure to further encourage renewable energy development. Even though the FIT was intended to provide a channel for renewable investment, the government in addition privately negotiated contracts with a Korean conglomerate under separate terms to build yet more renewable energy projects.

The FIT and the privately negotiated contracts were pursued with little regard for existing system plans. The Ontario government subsequently commissioned a replacement for the IPSP, now known as the Long-Term Energy Plan. In theory, the results of the Long-Term Energy Plan when complete will help to inform future procurement efforts, and possibly the evolution of the FIT. Despite initially acknowledging that rates would increase as a result of the GEA, effective January 2011, the government provided a 10% rebate on electricity bills of residential customers and small businesses.[34]

5.2 Use of the power sector to further public policy ends

The government's approach to the power sector in Ontario has begun to encompass a wider range of policy goals than simply reliable electricity at the lowest sustainable cost consistent with good environmental stewardship. While the initial plan to shut down Ontario's coal plants had a narrow intent – to improve air quality – and was accompanied by the effort to create the IPSP as a way of determining the best overall means to achieve the limited objective, the GEA uses the power sector as a form of industrial policy. The Ontario government has made claims that the GEA will result in 50,000 new jobs, for example. Leaving aside whether such claims are plausible (the combined employment of OPG and Hydro One is 17,500,[35] and the entire direct auto manufacturing industry in Ontario employs 38,000), there has been little published analysis regarding whether attempting to increase employment using a FIT program, with costs ultimately born by the ratepayer, is a least cost means of increasing employment.

5.3 Mistakes made

Many of the challenges that have arisen in Ontario have occurred because the province attempted to do too much and do it all too quickly. Mistakes were made by policymakers of all political persuasions. While market opening was exhaustively studied, in retrospect it could have been better designed. Major policy decisions since then have had far less scrutiny. In abandoning the market, the government, after appearing to put in place a process for long term

[34] Bloomberg. Accessed February 10, 2011. "Ontario's 20-Year Energy Plan to Boost Nuclear, Wind, Solar". <http://www.businessweek.com/news/2010-11-24/ontario-s-20-year-energy-plan-to-boost-nuclear-wind-solar.html>.

[35] OPG and Hydro One 2009 annual reports. Labour Statistics Division, Statistics Canada, Table 281-0024, NAICS Code 3361.

least cost planning, undercut that process with yet another set of initiatives. A summary of the biggest policy errors includes:

- unlike Alberta, which used contractual mechanisms to create multiple competitive players in the generation market via a power purchase agreement auctions (2000), ***Ontario failed to reduce OPG's market dominance*** by proceeding with a well planned plant or contractual divestiture process;

- ***market mechanisms were abandoned precipitously***, when the cause of the bill increases was in fact a mix of factors including opening the market at the beginning of the summer high demand period, adjustments to wires company charges to include a commercial return on capital, and the magnifying impact of the bimonthly billing cycle;

- after putting in place the IPSP and competitive contracting rounds consistent with the results of the IPSP, the ***GEA created an FIT mechanism which divorced procurement quantities from an assessment of projected need***;

- ***contracts were entered into outside of the competitive procurement rounds,*** often in response to ministerial directives;[36]

- ***FIT pays higher prices to less efficient resources*** even within the same renewable category, meaning that ultimately the province is not procuring as much renewable energy as it could for a given amount of money;[37] and

- by entering into a ***transaction with Samsung that was neither a competitive procurement nor based on the FIT***, the government implied that there was yet a third way to gain contracts in Ontario, and a means which fails to provide ratepayers with any evidence that the province is paying the lowest sustainable price for the goods and services to be provided.[38]

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[36] From March 2005 to September 2010, the Minister of Energy issued a total of 43 directives to the OPA, approximately 20 of which directed the OPA to contract with specific entities.

[37] Prices for renewable energy projects under the FIT program vary across and within technologies: landfill gas (10.3-11.1 cents/kWh); biogas (10.4-19.5 cents/kWh); waterpower (12.2-13.1 cents/kWh); biomass (13.0-13.8 cents/kWh); wind (13.5-19.0 cents/kWh); and solar PV (44.3-80.2 cents/kWh). By comparison, NV Energy and PG&E Solar, announced a 25-year PPA to purchase Solar PV at bid price of 24.6 cents/kWh; Source: OPA. "Feed-In Tariff Prices for Renewable Energy Projects in Ontario." August 13, 2010. <http://fit.powerauthority.on.ca/Storage/102/11128_FIT_Price_Schedule_August_13_2010.pdf>; Gunther Portfolio. "PG&E Solar PV Program PPA awaits final CPUC nod." July 7, 2010, <http://guntherportfolio.com/2010/07/pge-solar-pv-program-ppa-awaits-final-cpuc-nod/>

[38] In January 2010, the government of Ontario signed a $7 billion sole-source agreement with a consortium comprised of Samsung C&T Corporation and Korea Power Electric Corporation to install 2,000 MW of wind energy capacity and 500 MW of solar energy capacity between 2013 and 2017. Under this agreement, the consortium will receive dedicated access to transmission and an economic development adder of approximately $437 million (net present value) on top of preferential rates for renewable energy over the 25-year life of the agreement. Source: Government of Ontario. "Ontario Delivers $7 Billion Green Investment." January 21, 2010. <http://news.ontario.ca/mei/en/2010/01/backgrounder-20100121.html>

5.4 Likely price impact

The impact of this somewhat dizzying array of policy changes is that electricity prices in Ontario are likely to be higher than they otherwise needed to be, even when accounting for the province's environmental objectives. By abandoning both the market and least cost planning processes, the province risks having too much of the wrong type and size of generation in the wrong place, therefore leading to inefficient production and investment.

In previous work, LEI has estimated that costs to final consumers, from 2010 to 2025, could increase by $247 to $631 on average per household per year as a result of the GEA, excluding the harmonized sales tax.[39] Other experts have produced similar numbers. For example, Aegent Energy Advisors, in a study commissioned by Canadian Manufacturers & Exporters, projected that from 2011 to 2015, initiatives associated with the GEA will result in an electricity cost increase of $134 to $734, inclusive of the harmonized sales tax, on average per residential consumer each year.[40]

Recent LEI modeling suggests that by 2014 the Global Adjustment, which includes the cost of new contracts under FIT, could make up 57% of the commodity charge for power. While the share of the Global Adjustment declines over time, as Figure 40 illustrates, it does not reach zero until 2036 under a baseline scenario with low demand, low natural gas prices, and the existing level of nuclear installed capacity, suggesting that Ontario may be paying for significant amounts of capacity well before such capacity is needed.

Ironically, during periods of excess supply, while the GA rises, neighboring states and provinces benefit from low priced (or at times, negatively priced) exports from Ontario. Ontario ratepayers pay more, while importers elsewhere pay less.

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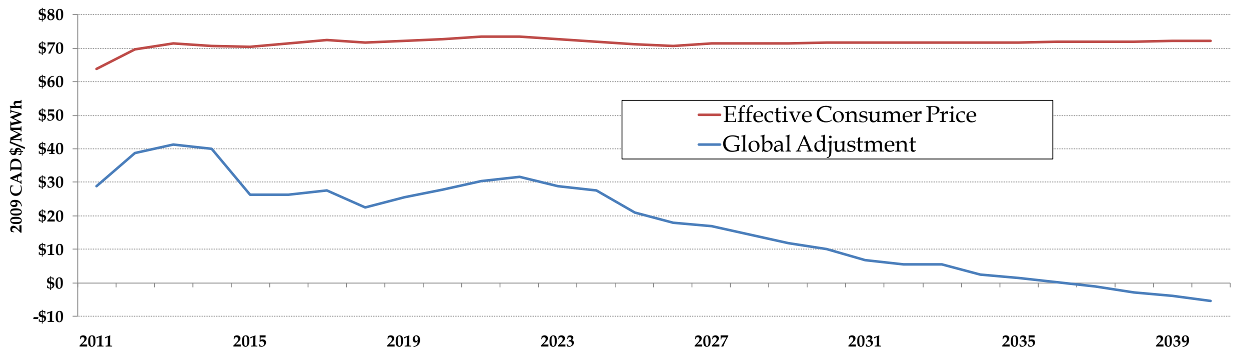
[39] LEI, "*Examining the potential cost of the Ontario Green Energy Act, 2009*". <http://www.londoneconomics.com/pdfs/Executive-Summary-Potential-Cost-of-the-Green-Energy-Act.pdf>. April 20, 2009.

[40] Aegent Energy Advisors projected cost increases on a monthly basis. To arrive at the annual values, we multiplied these estimates by 12. Aegent Energy Advisors, "Ontario Electricity Total Bill Impact Analysis August 2011 to July 2015," August 26, 2010 <http://on.cme-mec.ca/download.php?file=gecusdzx.pdf>.

Figure 40. Projected Global Adjustment payments and effective consumer prices in Ontario



Source: LEI estimates

5.5 Contrast with Alberta

Ontario has turned its back on the market twice: first by diminishing the number of generators whose long term profits are dependent on either the HOEP or private contracts, and second by replacing competitive contracting processes with administered pricing under the FIT. Neither step was necessary to achieve Ontario's environmental goals; resulting increased power costs may undermine its job creation goals.

By contrast, in an open competitive generation market, Alberta has, over the past decade, added 631 MW of new wind, without the need for significant government intervention.[41] Private investors seriously considered the addition of nuclear power, with the go/no go decision resting on market signals. While policymakers have sought to shape market evolution and have been attentive to issues such as reliability and competition, the government has (with the exception of transmission issues) largely respected the independence both of the institutions it has created and the private or municipal actors within those institutions. Thus, while transmission investment may lead to an increase in rates to Alberta consumers over time, those consumers face less risk of also having to pay for generation oversupply stemming from failure to rely on competitive market forces.

[41] As a proportion of current installed capacity, Alberta added 5% in wind-based resources. By comparison, over the same timeframe, Ontario added 1,100 MW of new wind or approximately 3% of 2010 installed capacity. The Independent Electricity System Operator (IESO), September 24, 2010. <http://www.ieso.ca/imoweb/siteshared/windtracker.asp>.

6 Implications for Alberta

When carefully examined, electricity rates in Alberta are within range of rates in other provinces in Canada. As provinces across Canada make investments in their electricity sector, the gap between Alberta and other provinces may narrow. However, in addition to being cost competitive when rates are examined on a full cost basis, the Alberta market has a number of other advantages. These include appropriate risk allocation, substantial transparency, a clear separation between policymakers and power sector companies, and the ability of customers to hedge a large portion of their bill, unlike other jurisdictions where no stable, long-term pricing options exist. While recent changes in transmission policy somewhat undermine some of these advantages, they nonetheless provide greater economic efficiency than arrangements in other provinces.

6.1 Risk allocation

The Alberta market design seeks to allocate risk to the parties best able to manage it. If generators build too many plants relative to actual demand, it is the generators who suffer, not the ratepayers. In the current low wholesale price environment, unhedged generators face lower profits or, in some cases, losses. Were the Alberta generation sector a regulated environment, customers could perversely see increases in their bills as a result of declining demand, since utilities would seek to recover their lost profits in rates. In the Alberta market design, unhedged generators face volume risk; they also are at risk if their projects exceed budget. Such a market design helps to prevent phenomena like the Darlington nuclear plant in Ontario, which was built in anticipation of load growth which did not occur and was massively over budget. Ontario ratepayers continue to pay for these cost overruns 17 years after the plant was completed.[42]

6.2 Transparency

Because of the risk allocation described above, only shareholders suffer when generation planning goes awry, and if they do, they have the ability to change management. Shareholder scrutiny may help prevent poor decisions, just as regulatory oversight may in a traditional regulated environment. It is more difficult in Alberta than in other provinces for ministries to rule by directive because the Alberta government has no provincially-owned companies to issue directives to. Utility planning is open, and subject to AUC oversight except where specified by law.[43] Generators and IPPs answer to their shareholders, and the constant consideration of fiduciary duty may be more potent than the fear of a potentially distant election. While many provinces have worked to improve independent oversight of provincially-owned utilities, governments have often proved less capable of regulating themselves than they are of regulating private entities.

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[42] The original cost estimate for Darlington generating station was $3.9 billion; it ended up costing $14.4 billion. It currently accounts for a sizable component of the Global Adjustment. Eileen O'Grady, "OPG Ontario Darlington 4 reactor back – report," Reuters, August 23, 2010.

[43] Transmission is an unfortunate exception.

6.3 Avoidance of use of power sector for political ends

Canadian provincial governments have found it difficult to resist the temptation to use provincially owned utilities to further various policy aims. The power sector has been seen as a means to create jobs or for rural development, sometimes without exploration of whether a provincially owned utility is indeed the most cost effective means of achieving these ends. Provincial ownership makes layoff and siting decisions more politicized than they would be at a private company. Currently, Albertans pay only for power through their electricity rates. Public policy initiatives are funded by the taxpayer, not the ratepayer.

6.4 Ability of customers to hedge

Figure 41. Options available to Alberta residential and industrial customers

Product	Product Description
5 year fixed	Fixed price electricity contract
4 year fixed	Fixed price electricity contract
1 year fixed	Fixed price electricity contract
Dual Fuel Products	Due to the synergies between natural gas and electricity marketing, several retailers offer dual fuel products
Duel Fuel Seasonal	Flow-through price plans for natural gas include additional $/GJ fee based on Summer (April 1 to Sept. 30) and Winter (October 1 to March 31)
Variable Price Products	Floating price plans, flow-through prices for electricity rate (or natural gas if dual fuel product) are based on hourly Alberta Pool prices (daily wholesale market prices in Alberta for natural gas) with additional charges
Green Energy Products	Products made from renewable sources, such as wind

Source: Government of Alberta. "Retail Market Review". April 15, 2010. Pg. 19. Manitoba Hydro. October 26, 2010.

Of all provinces, Alberta provides its customers with the greatest opportunities to hedge. By contrast, consumers in Ontario cannot hedge against the Global Adjustment; if the Ontario Power Authority chooses to sign additional contracts, regardless of the supply situation, all customers will pay. Customers are exposed to similar impacts in other provinces: if BC Hydro overcontracts with renewable IPPs in hopes of an export market which doesn't materialize, or if

Manitoba Hydro or SaskPower overbuild, there is no practical way for customers to avoid costs or hedge against them other than through pleading to the government.

Alberta customers have choices that most consumers in other Canadian provinces do not have. The ability to hedge, as well as the additional options available through retailers, provides additional value over and above the relative level of prices.

6.5 Concluding remarks

Were it not for the extent and timing of planned transmission investments, it is possible that Alberta delivered power costs would become yet more competitive when compared to other Canadian provinces. Given that other provinces are also considering significant investments in electricity infrastructure, Alberta may maintain its operation even if the proposed transmission investment proceeds as planned. There are a host of benefits to allowing the market to determine the price of power. These include transferring risk to investors and away from consumers, relieving taxpayers of the cost and risk of utility debt, encouraging efficient consumption decisions and enabling provinces to focus scarce resources on activities which the private sector cannot perform, such as social programs. In addition to these structural benefits, Alberta's reliance on market principles has produced genuine price advantages for its residential and industrial customers. Should the policy environment in Alberta change, additional upward pressure on delivered electricity rates may result.

7 Addendum

Following submission of this report, LEI was asked to incorporate any changes to the transmission investment cost estimates during the first quarter of 2011 for all provinces and update the 2015 rate outlook. This section discusses the impact of 2011 announcements on calculations found within the report.

7.1 Updated transmission investment costs

Alberta is the only province to have updated the transmission investment cost estimates since this report was initially written. Two new projects were approved by AUC in the first quarter of 2011. In addition, some of the cost estimates have been updated. As a result, C$294.8 million in additional investment appears in the Q1 numbers relative to the Q4 numbers that are used in the report. Figure 42 shows the difference between the cost estimates used in the report and the presentation.

Figure 42. Comparison of transmission investment costs in Q4 2010 and Q1 2011

Name of project	Total (millions)				Date in service
	Q1 2011		Q4 2010		
9L66 240kV Line Relocation	C$	1.2	C$	1.2	2011
Ft McMurray Area 144 kV Reinforcement	C$	39.0	NA		2012
North Central Region Transmission Development	C$	51.8	C$	51.8	2013
Calgary Business District	C$	62.4	C$	62.4	2011
South East Transmission Reinforcement	C$	74.5	C$	74.5	2011
Yellowhead Area Transmission Development	C$	87.8	C$	87.8	2012
ENMAX No. 65 Substation	C$	110.0	C$	110.0	2012
Edmonton Region 240kV Line Upgrades	C$	125.4	C$	125.4	2012
North Ft McMurrary Transmission Development	C$	237.4	NA		2013
North West Transmission Development	C$	262.5	C$	262.5	2012
Hanna Region Transmission Development	C$	848.7	C$	848.7	2013
Southern Alberta Transmission Reinforcement	C$	1,826.4	C$	1,808.0	2015
North South Transmission Reinforcement	C$	2,390.0	C$	2,390.0	2014
Alberta Industrial Heartland Bulk Transmission Development	C$	3,013.2	C$	3,013.2	2013
Total	**C$**	**9,130.3**	**C$**	**8,835.5**	

Source: Alberta Electric System Operator, <http://www.aeso.ca/downloads/2010_Q4_Tx_System_Quarterly_Report_R1.pdf>. 2010 Q4 report."http://www.aeso.ca/downloads/2011_Q1_Tx_System_Quarterly_Report_R1.pdf". 2011 Q1 report.

Note: only projects that are approved by AUC and expected to come in service in 2011-15 are included. Q4 numbers are used in the report; C$294.8 million in additional investment appears in the Q1 numbers.

NA: Not Approved by AUC

This additional transmission cost results in a slightly higher residential and industrial rate outlook. Compared to the rates previously provided in the report, rates are higher by an average of 0.03 cents/kWh due to the additional transmission investment.

Figure 43. Updated residential customers price outlook, 2011-15

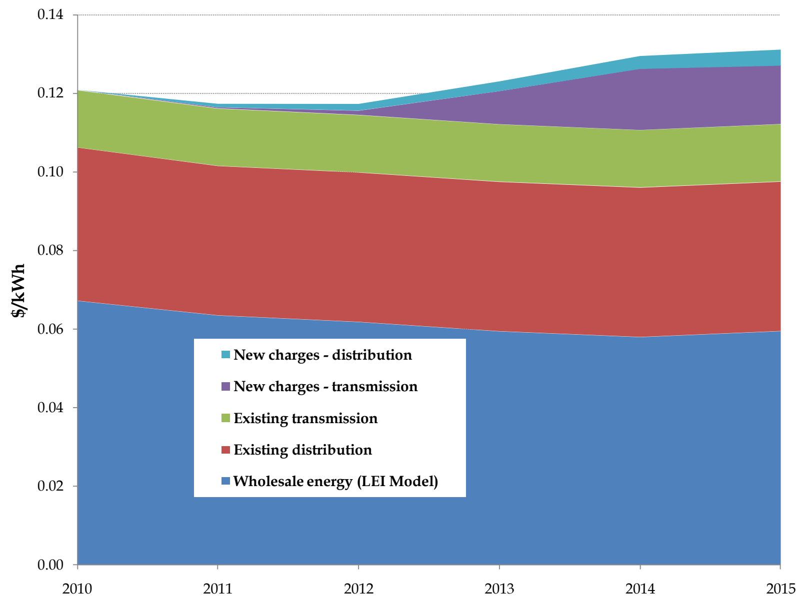
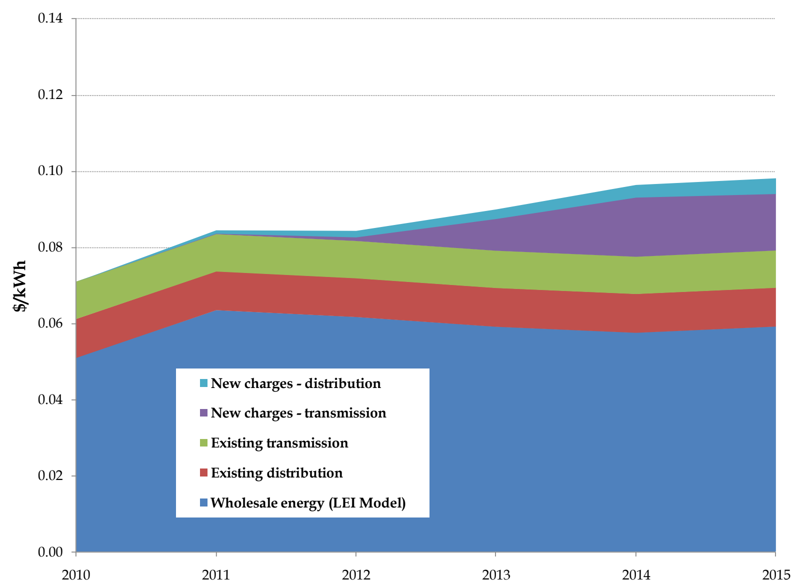


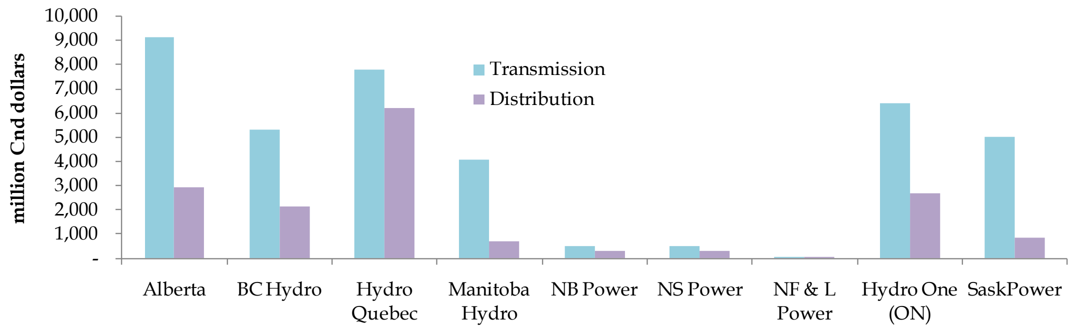
Figure 44. Updated industrial customers price outlook, 2011-15



7.2 Updated rate outlook across Canada in 2015

Figure 46 and Figure 47 show the updated rate outlook for Alberta compared to other provinces for residential and industrial customers. Compared to the report, the average rate across Canada in 2015 is higher by 0.005 cents/kWh due to the additional transmission investment in Alberta.

Figure 45. Updated transmission and distribution capital expenditure, 2011-15



Note: Compared to the report, Alberta transmission costs are higher by C$294.8 million.

Figure 46. Updated expected residential rates in 2015

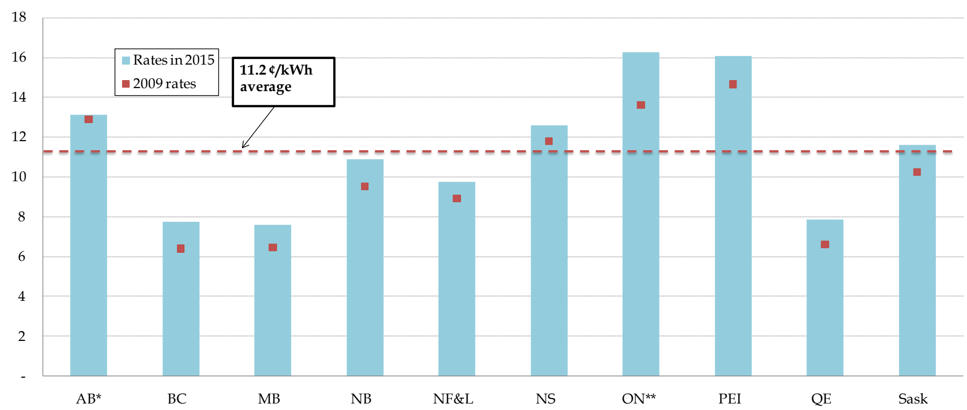
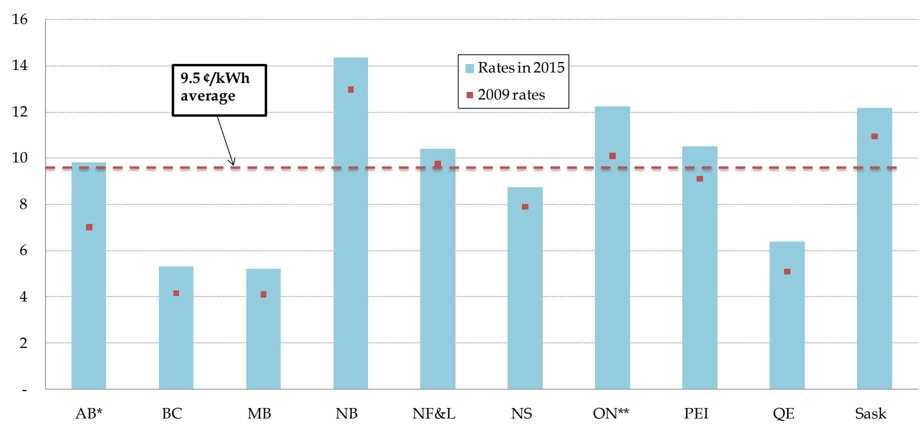


Figure 47. Updated expected industrial rates in 2015



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9 Appendix B: comparing Alberta 2009 industrial rates with US industrial rates

Exchange rate (2009 average)		0.889
State/Province	Industrial rates (US cent/kWh)	Industrial rates (CDN cent/kWh)
Washington	3.93	4.42
Louisiana	4.57	5.14
Wyoming	4.87	5.48
Oklahoma	5.10	5.73
Kentucky	5.16	5.80
Iowa	5.42	6.09
West Virginia	5.43	6.11
Montana	5.64	6.34
Utah	5.69	6.40
South Dakota	5.70	6.41
Indiana	5.75	6.47
Oregon	5.86	6.59
South Carolina	5.86	6.59
North Carolina	5.90	6.63
Idaho	5.92	6.66
Nebraska	5.93	6.67
New Mexico	5.96	6.70
Arkansas	6.01	6.76
Alberta	6.23	7.00
North Dakota	6.23	7.01
Missouri	6.30	7.08
Colorado	6.33	7.12
Kansas	6.43	7.23
Mississippi	6.86	7.71
Minnesota	6.90	7.76
Virginia	6.97	7.84
Georgia	6.98	7.85
Texas	6.99	7.86
Tennessee	7.04	7.92
Alabama	7.06	7.94
Arizona	7.11	7.99
Wisconsin	7.18	8.07
Ohio	7.24	8.14
Pennsylvania	7.61	8.56
Illinois	7.64	8.59
Michigan	7.68	8.64
Nevada	8.25	9.28
Delaware	8.94	10.05
Florida	9.09	10.22
Vermont	9.23	10.38
Maryland	9.36	10.52
New York	9.44	10.61
Maine	9.49	10.67
Massachusetts	10.57	11.89
California	11.59	13.03
New Jersey	12.52	14.08
Rhode Island	13.43	15.10
Alaska	13.46	15.13
New Hampshire	13.79	15.51
Hawaii	16.03	18.02
Connecticut	19.75	22.21

Note: US 2009 industrial rates are based on Form EIA-826, "Monthly Electric Sales and Revenue Report with State Distributions Report", as of June 2010.

All rates listed are as of June 2009 and are displayed in Canadian cents per kWh using average US dollar to Canadian dollar exchange rate in June 2009. Source: Bank of Canada

10 Appendix C: Residential and industrial rate calculations

Residential electricity rates in Alberta consist of a wholesale energy cost component, a distribution component, a transmission component, as well as regulatory charges. LEI has estimated the residential electricity rate for customers receiving service from each of the four largest utilities. LEI has also calculated a weighted average for the province based on the relative number of customers served by each of the four utilities. Rate calculations exclude transitional rate riders. The rates are estimated through the following steps:

1 The wholesale energy cost component is equal to the annual average Regulated Rate Option (RRO) tariff for 2009 and 2010, in "dollars per kWh", for each utility.[44] This value is converted to "cents per kWh" by multiplying by 100.

2 Distribution charges, which consist of both fixed monthly (dollars per day) and variable (cents per kWh) charges, are based on each utility's 2009-2010 Alberta Utilities Commission (AUC) rate application.

   a Fixed monthly charges, which are reflected as a "dollar per day" charge, are converted to "cents per kWh" based on the assumption that the average household consumes 600 kWh of electricity per month. First, the "dollar per day" value is multiplied by 30.42 days (the average number of days per month per non-leap year) to get to a "dollar per month" value. The "dollar per month" value is then divided by 600 kWh per month (the assumed average residential consumption) to get a "dollars per kWh" value. Lastly, the "dollars per kWh" value is multiplied by 100 to get to a "cents per kWh" value.

3 Transmission charges, which for residential customers are purely volumetric (cents per kWh), are based on each utility's 2009-2010 AUC rate application.

4 The average Balancing Pool Adjustment Credit for 2010 is estimated to be 0.3 cents per kWh. To arrive at this number, we take the average of 0.4 cents per kWh from January to June and 0.2 cents per kWh from July to December. On a monthly basis, this comes to $1.80 per month, assuming monthly consumption of 600 kWh. The Balancing Pool Adjustment Credit for 2009 is 0.65 cents per kWh, or $4 per month at 600 kWh per month consumption. This is based on AESO's filing with AUC.[45] The Balancing Pool Adjustment Credit appears as a rebate on consumers bills.

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[44] FortisAlberta's cost calculator <http://www.fortisalberta.com/Default.aspx?cid=359&lang=1> assumes an all-in cost (generation, distribution, transmission, and regulatory charges) of 15 cents/kWh for residential customers. It is important to note that the residential rates fluctuate every month as the underlying RRO generation component changes.

[45] Alberta Utility Commission. Order #: U2008-356 2009 Rider F. 24 November 2008. Page 2; Alberta Utility Commission. Decision 2010-257, 2010 Rider F Amendment. 4 June 2010. Page 2.

5 As mentioned previously, the weighted average cost for Alberta is estimated by averaging the individual cost for each of the four utilities and weighting by the number of customers.

Industrial electricity rates in Alberta consist of similar charges to residential electricity rates. They are composed of a generation component, distribution and transmission charges, and a regulatory component.

Transmission and distribution charges are from the 2009-2010 rates filings of each utility with AUC. AESO files additional revenue requirements with AUC to manage the transmission system in Alberta, a portion of which are passed on to industrial customers. These charges include both volumetric and fixed components such as demand charges and system access service charges. The rates are estimated through the following steps:

1 The generation component of industrial electricity rates is equivalent to the actual wholesale price of electricity on the Alberta Electricity System Operator (AESO) market, adjusted for the typical load shape of industrial customers.[46] The arithmetic average annual electricity prices on the AESO administered market in 2009 and 2010 were $47.80 per MWh $50.89 per MWh, respectively. To calculate the average price paid by an industrial consumer, the average annual AESO price is adjusted to reflect the load shape of a typical industrial customer. In this case, the annual average AESO prices are multiplied by 1.068. The 6.8% adjustment factor represents the typical premium that an indicative industrial customer can expect to pay relative to the average spot market price due to a higher degree of peak consumption.

2 Distribution charges, which consist of both demand (cents per day, cents per kVA per day, or cents per kW per day) and variable (cents per kWh) charges, are based on each utility's 2009-2010 AUC rate application

  a Demand charges, which are reflected as either "cents per day", "cents per kVA per day", or "cents per kW per day", are converted to "cents per kWh" based on the assumption that the average industrial customer consumes 49,000 kWh of electricity per month and has a load factor of 0.8 and a power factor of 0.9.[47]

    i "Cents per kW per day" and "cents per kVA per day" charges are converted to "cents per kWh" in the following manner. First, the assumed 49,000 kWh monthly consumption is converted into an estimated peak daily demand by

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[46] EPCOR estimates monthly default supply energy prices, which incorporate the impact of a typical customer class load shape. We have used the five year (2006-2010) average load shape premium, as reported by EPCOR, for demand less than 75 kW. <http://www.epcor.ca/en-ca/Customers/electricity-customers/electricity-rates/default-supply-rates/Pages/actuals.aspx>.

[47] Load factor refers to the ratio of average daily demand to peak daily demand. 80% load factor was obtained from AESO. 2008. "Impact of long-term transmission spending on transmission charges". page 2. Power factor refers to the ratio of kW to kVA.

dividing by average days in a month, and then by the assumed load factor of 0.8. Then, and if necessary, "cents per kVA per day" charges are converted into "cents per kW per day" by dividing by the 0.9 power factor assumption. The "cents per kW per day" charges are then multiplied by the assumed daily peak demand and the average number of days per month to arrive at a "cents per month" charge. This "cents per month" charge is then divided by the assumed monthly consumption of 49,000 kWh to obtain the final "cents per kWh" estimate.

ii "Cents per day" charges are converted to "cents per kWh" by multiplying by the average number of days per month (30.42) and then divided by the assumed monthly consumption (49,000 kWh) to obtain "cents per kWh".

3 The average Balancing Pool Adjustment Credit for 2010 is estimated to be 0.3 cents per kWh. To arrive at this number, we take the average of 0.4 cents per kWh from January to June and 0.2 cents per kWh from July to December. On a monthly basis, this comes to $1.80 per month, assuming monthly consumption of 600 kWh. The Balancing Pool Adjustment Credit for 2009 is 0.65 cents per kWh, or $4 per month at 600 kWh per month consumption. This is based on AESO's filing with AUC.[48] The Balancing Pool Adjustment Credit appears as a rebate on consumers bills.

4 As mentioned previously, the weighted average cost for Alberta is estimated by averaging the individual cost for each of the four utilities and weighting by the number of customers.

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[48] Alberta Utility Commission. Order #: U2008-356 2009 Rider F. 24 November 2008. Page 2; Alberta Utility Commission. Decision 2010-257, 2010 Rider F Amendment. 4 June 2010. Page 2.

Figure 48. Utility A rates, 2010

Residential		Transmission	Distribution	Load factor	80%	
For all kWh delivered (cent/kWh)		1.720	1.405	Residential consumption	**600**	kWh/Month
Sub-Total (cent/kWh)		1.720	1.405	Industrial consumption	**49,000**	kWh/Month
Charges ($ per day)		-	0.534	kVA to kW	**0.90**	Assumption
Sub-Total (cent/kWh)		-	2.707			
Total (cent/kWh)		**1.720**	**4.112**			
Balancing Pool (cent/kWh)	(0.300)					
RRO (2010 average)	6.589					
Final Rate (cent/kWh)	**12.120**					

Industrial		Transmission	Distribution		
For all kWh delivered (cent/kWh)		0.582	-		
Sub-Total (cent/kWh)		0.582	-		
For each kW of Capacity ($ per kW per month)		3.243	5.379		
Sub-Total (cent/kWh)		0.300	0.430		
Total (cent/kWh)		**0.882**	**0.430**		
Balancing Pool (cent/kWh)	(0.300)				
Wholesale charges (cent/kWh)	5.434			Adjustor for wholesale charges to account for load shape	6.80%
Final Rate (cent/kWh)	**6.447**				

Figure 49. Utility B rates, 2010

Residential		Transmission	Distribution	Load factor	80%	
Energy charges (cent/kWh)		1.750	5.310	Residential consumption	**600**	kWh/Month
Sub-Total (cent/kWh)		1.750	5.310	Industrial consumption	**49,000**	kWh/Month
Customer charges (cent/day)		-	90.380	kVA to kW	**0.90**	Assumption
Sub-Total (cent/kWh)		-	4.582			
Total (cent/kWh)		**1.750**	**9.892**			
Balancing Pool (cent/kWh)	(0.300)					
RRO (2010 average)	6.877					
Final Rate (cent/kWh)	**18.219**					

Industrial		Transmission	Distribution		
Energy charges (cent/kWh)		0.420	-		
Sub-Total (cent/kWh)		0.420	-		
First 500 kW demand (cent/kW/day)		13.61	20.73		
Customer charges (cent/day)		-	214.46		
Services ($/day)		2.207			
Sub-Total (cent/kWh)		0.782	1.018		
Total (cent/kWh)		**1.202**	**1.018**		
Balancing Pool (cent/kWh)	(0.300)				
Wholesale charges (cent/kWh)	5.434			Adjustor for wholesale charges to account for load shape	6.80%
Final Rate (cent/kWh)	**7.354**				

Figure 50. Utility C rates, 2010

Residential		Transmission	Distribution
Energy charges (cent/kWh)		1.337	0.761
Sub-Total (cent/kWh)		1.337	0.761
Service charges (cent/day)		-	31.629
Sub-Total (cent/kWh)		-	1.603
Total (cent/kWh)		**1.337**	**2.364**
Administration charges (cent/day)	1.203		
Balancing Pool (cent/kWh)	(0.300)		
RRO (2010 average)	6.872		
Final Rate (cent/kWh)	**11.477**		

Load factor	**80%**	
Residential consumption	**600**	kWh/Month
Industrial consumption	**49,000**	kWh/Month
kVA to kW	**0.90**	Assumption

Industrial	Energy	Transmission	Distribution
Energy charges (cent/kWh)		0.439	0.514
Sub-Total (cent/kWh)		0.516	0.514
Demand charges (cent/kVA/day)		8.075	1.367
Customer charges ($/day)			12.528
Sub-Total (cent/kWh)		0.415	0.828
Total (cent/kWh)		**0.932**	**1.342**
Balancing Pool (cent/kWh)	(0.300)		
Wholesale charges (cent/kWh)	5.434		
Final Rate (cent/kWh)	**7.408**		

Adjustor for wholesale charges to account for load shape	6.80%

Figure 51. Utility D rates, 2010

Residential		Transmission	Distribution
Energy charges (cent/kWh)		1.259	0.492
Sub-Total (cent/kWh)		1.259	0.492
Customer charges (cent/day)		-	40.758
Sub-Total (cent/kWh)		-	2.066
Total (cent/kWh)		**1.259**	**2.558**
Balancing Pool (cent/kWh)	(0.300)		
RRO (2010 average)	6.594		
Final Rate (cent/kWh)	**10.111**		

Load factor	**80%**	
Residential consumption	**600**	kWh/Month
Industrial consumption	**49,000**	kWh/Month
kVA to kW	**0.90**	Assumption

Industrial		Transmission	Distribution
Energy charges (cent/kWh)		0.534	0.243
Sub-Total (cent/kWh)		0.534	0.243
Demand charges(cent/kVA/day)		6.235	8.399
Customer charges (cent/day)		-	34.542
Sub-Total (cent/kWh)		0.199	0.416
Total (cent/kWh)		**0.733**	**0.659**
Balancing Pool (cent/kWh)	(0.300)		
Wholesale charges (cent/kWh)	5.434		
Final Rate (cent/kWh)	**6.526**		

Adjustor for wholesale charges to account for load shape	6.80%

Figure 52. Utility A rates, 2009

Residential		Transmission	Distribution
For all kWh delivered (cent/kWh)		1.494	1.277
Sub-Total (cent/kWh)		1.494	1.277
Charges ($ per day)		-	0.486
Sub-Total (cent/kWh)		-	2.464
Total (cent/kWh)		**1.494**	**3.741**
Balancing Pool (cent/kWh)	(0.650)		
RRO (2009 average)	7.901		
Final Rate (cent/kWh)	**12.486**		

Load factor	**80%**	
Residential consumption	**600**	kWh/Month
Industrial consumption	**49,000**	kWh/Month
kVA to kW	**0.90**	Assumption

Industrial		Transmission	Distribution
For all kWh delivered (cent/kWh)		0.523	-
Sub-Total (cent/kWh)		0.523	-
For each kW of Capacity ($ per kW per day)		2.916	5.379
Sub-Total (cent/kWh)		0.956	1.194
Total (cent/kWh)		**1.479**	**1.194**
Balancing Pool (cent/kWh)	(0.650)		
Wholesale charges (cent/kWh)	5.106		
Final Rate (cent/kWh)	**7.129**		

Adjustor for wholesale charges to account for load shape	**6.80%**

Figure 53. Utility B rates, 2009

Residential		Transmission	Distribution
Energy charges (cent/kWh)		1.610	5.400
Sub-Total (cent/kWh)		1.610	5.400
Customer charges (cent/day)		-	89.900
Sub-Total (cent/kWh)		-	4.557
Total (cent/kWh)		**1.610**	**9.957**
Balancing Pool (cent/kWh)	(0.650)		
RRO (2009 average)	8.386		
Final Rate (cent/kWh)	**19.304**		

Load factor	**80%**	
Residential consumption	**600**	kWh/Month
Industrial consumption	**49,000**	kWh/Month
kVA to kW	**0.90**	Assumption

Industrial		Transmission	Distribution
Energy charges (cent/kWh)		0.480	-
Sub-Total (cent/kWh)		0.480	-
First 500 kW demand (cent/kW/day)		11.680	20.180
Customer charges (cent/day)		-	215.065
Services ($/day)		2.185	-
Sub-Total (cent/kWh)		1.628	1.498
Total (cent/kWh)		**2.108**	**1.498**
Balancing Pool (cent/kWh)	(0.650)		
Wholesale charges (cent/kWh)	5.106		
Final Rate (cent/kWh)	**8.062**		

Adjustor for wholesale charges to account for load shape	**6.80%**

Figure 54. Utility C rates, 2009

Residential		Transmission	Distribution
Energy charges (cent/kWh)		1.337	0.761
Sub-Total (cent/kWh)		1.337	0.761
Service charges (cent/day)		-	31.629
Sub-Total (cent/kWh)		-	1.403
Total (cent/kWh)		**1.337**	**2.164**
Administration charges (cent/day)	1.203		
Balancing Pool (cent/kWh)	(0.650)		
RRO (2009 average)	8.259		
Final Rate (cent/kWh)	**12.313**		

Load factor	80%	
Residential consumption	600	kWh/Month
Industrial consumption	49,000	kWh/Month
kVA to kW	0.90	Assumption

Industrial		Transmission	Distribution
Energy charges (cent/kWh)		0.516	0.514
Sub-Total (cent/kWh)		0.516	0.514
Demand charges (cent/kVA/day)		8.075	1.367
Customer charges ($/day)		-	12.528
Sub-Total (cent/kWh)		0.986	0.682
Total (cent/kWh)		**1.503**	**1.196**
Balancing Pool (cent/kWh)	(0.650)		
Wholesale charges (cent/kWh)	5.106		
Final Rate (cent/kWh)	**7.154**		

Adjustor for wholesale charges to account for load shape	6.80%

Figure 55. Utility D rates, 2009

Residential		Transmission	Distribution
Energy charges (cent/kWh)		1.259	0.492
Sub-Total (cent/kWh)		1.259	0.492
Customer charges (cent/day)		-	40.758
Sub-Total (cent/kWh)		-	2.066
Total (cent/kWh)		**1.259**	**2.558**
Balancing Pool (cent/kWh)	(0.650)		
RRO (2009 average)	7.910		
Final Rate (cent/kWh)	**11.077**		

Load factor	80%	
Residential consumption	600	kWh/Month
Industrial consumption	49,000	kWh/Month
kVA to kW	0.90	Assumption

Industrial		Transmission	Distribution
Energy charges (cent/kWh)		0.534	0.243
Sub-Total (cent/kWh)		0.534	0.243
Demand charges(cent/kVA/day)		6.235	8.399
Customer charges (cent/day)		-	34.542
Sub-Total (cent/kWh)		0.361	0.587
Total (cent/kWh)		**0.895**	**0.830**
Balancing Pool (cent/kWh)	(0.650)		
Wholesale charges (cent/kWh)	5.106		
Final Rate (cent/kWh)	**6.181**		

Adjustor for wholesale charges to account for load shape	6.80%

11 Appendix D: Background on LEI

11.1 LEI activities

London Economics International LLC (LEI) is a global economic, financial and strategic advisory professional services firm specializing in energy and infrastructure. The firm combines detailed understanding of specific network and commodity industries, such as electricity generation and distribution, with a suite of proprietary quantitative models to produce reliable and comprehensive results. LEI is involved in strategic consultancy, with a key differentiating factor from its competitors in combining strategic analysis with an in depth focus and understanding of the dynamics of the energy sector. The firm has advised private sector clients, market institutions, and governments on privatization, asset valuation, deregulation, tariff design, market power, and strategy in virtually all deregulated markets worldwide.

The firm has worked with a number of infrastructure companies, financial institutions, multilateral institutions, multilateral organizations, utilities, and government institutions in evaluating energy and water sector transactions, financing mechanisms, and providing advice on both strategic direction and operations. Infrastructure market design, regulatory economics, privatization and unbundling, and advice on mergers and asset acquisitions are among LEI's core competencies. LEI has worked in Alberta on a variety of engagements since deregulation of the market in the mid-1990s, has deep expertise in renewable energy policies and markets across North America and the rest of the world, and has a developed practice area in price forecasting, asset valuation and strategic advisory services for generation facilities

11.2 LEI experience in Alberta

LEI has extensive experience in the Alberta market having worked on market design, asset valuations, contract evaluation, price forecasting, market power, and ratemaking design for a variety of entities (including the independent system operator, generators, transmission companies and distribution companies) since the mid-1990s. This experience includes (but is not limited to):

- ***Formula-based ratemaking expert testimony*:** Supported ENMAX, prepare a filing for its regulator proposing a formula-based tariff-setting scheme. Developed a formula for periodic adjustments to an average tariff metric based on an inflation factor, efficiency factor, the impact of capital investments, operational performance relative to defined metrics; and defined mechanisms for additional adjustments based on force majeure and financial performance outside a defined range. Provided strategic advice to the CEO and other senior managers on presenting the firm's proposal to the regulator and other stakeholders; and provided expert testimony in support of the firm's filing to its regulator.

- ***Contract valuation:*** LEI prepared an expert report regarding a dispute over contract valuation in Alberta. LEI analyzed the contract and the broader economic environment and market fundamentals to determine the value of the contract as of that date. The analysis involved economic modeling to provide energy market price, volume and revenue forecasts. We also valued the contract using cost, market and income valuation approaches.

- ***Evaluation of wind power projects:*** LEI provided analysis of the current regulatory framework and potential revenue sources for a portfolio of wind power projects in Alberta, including detailed a forecast of electricity prices and a discussion of the market dynamics, which provided the basis for determining the value of wind projects. The engagement also included a discussion of the sale of RECs to the US.

- ***Comprehensive studies of the Alberta electricity market:*** For a variety of clients, LEI has produced a complete study of the Alberta electricity market. We have reported on the current regulatory status and expected regulatory changes, evaluated the market participants, discussed impending developments and analyzed the current and future direction of the market. Using our proprietary forecasting tool, LEI has developed long term price projections and analyzed the sensitivity of prices to changes in underlying market conditions.

- ***Alberta Electricity Industry Structure Review:*** LEI performed the Electricity Industry Structure Review, which involved analysis of the roles of the Power Pool, the Transmission Administrator, the Market Surveillance Administrator, the Balancing Pool, and the System Controller. LEI performed extensive stakeholder consultation, as well as preparing analysis of how these roles are performed in ten competitive wholesale markets worldwide. We then created a series of models for the evolution of all the entities studied, as well as for the organization of the industry as a whole. These models, after further stakeholder interaction and discussion with the government were distilled into final recommendations regarding how the institutions should be structured in the future.

- ***Real options-based valuation:*** LEI was retained by the Balancing Pool of Alberta to conduct a real options-based valuation of one specific SCGT generation unit to provide a realistic, market-based foundation to determine the reservation price of the unit contracts for that plant.

- ***White paper analysis for stakeholders in response to Alberta Department of Energy's regulations on market power:*** in response to government proposed policies on what defined market analysis on the proposed market power tests to be added to regulation, LEI wrote a paper specifically demonstrating the adverse effects of the 20% hard cap market share limit proposed by the Department of Energy. The white paper was filed as testimony with the Department of Energy in their consultation on Section 6 of the Electric Utilities Act.

In addition to the above mentioned project experience, LEI publishes semi-annual regional market updates and 10-year energy price forecasts for major markets in North America (including Alberta) and around the world through London Economics Press (LEP).[49] Along

[49] London Economics Press. <http://londoneconomicspress.com/>.

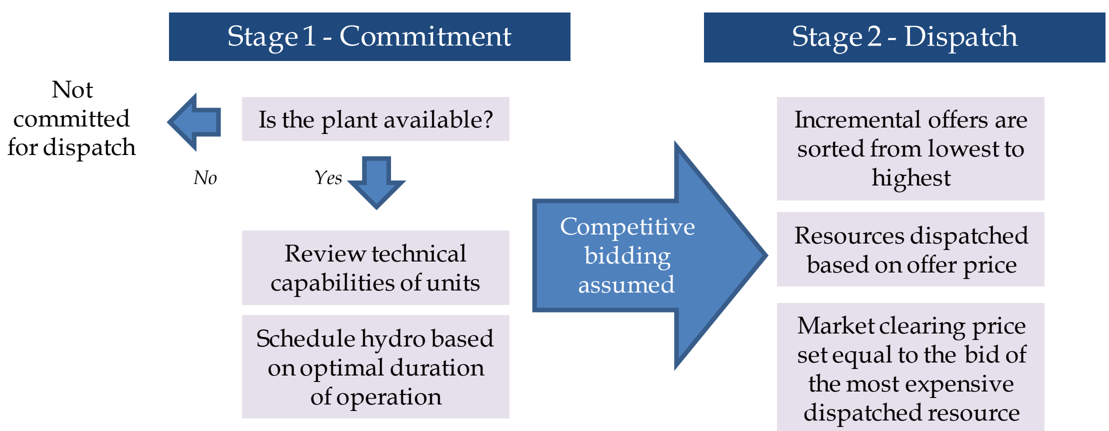
with providing price projections, the reports highlight major developments in each of the regions as well as the underlying structural dynamics. LEI also provides more detailed regional market price forecasts tailored to a client's individual needs, including longer time horizons and forecasting of plant-specific revenues or the impact of structural or market design changes.

11.3 LEI modeling tools

LEI employs a proprietary simulation model, POOLMod, to forecast wholesale energy prices in Alberta and other organized electricity markets. POOLMod simulates the dispatch of generating resources in the market, subject to least cost dispatch principles, to meet projected hourly load and technical assumptions on generation operating capacity and availability of transmission.

POOLMod consists of a number of key algorithms, such as maintenance scheduling, assignment of stochastic forced outages, hydro shadow pricing, commitment, and dispatch. The first stage of analysis requires the development of an availability schedule for system resources. First, POOLMod determines a "near optimal" maintenance schedule on an annual basis, accounting for the need to preserve regional reserve margins across the year and a reasonable baseload, mid-merit, and peaking capacity mix. It then allocates forced (unplanned) outages randomly across the year based on the forced outage rate specified for each resource.

Figure 56. POOLMod's Two-stage Process



POOLMod then commits and dispatches plants on a daily basis. Commitment is based on the schedule of available plants net of maintenance, and takes into consideration the technical requirements of the units (such as start/stop capabilities, start costs (if any), and minimum on and off times). During the commitment procedure, hydro resources are scheduled according to the optimal duration of operation in the scheduled day. They are then given a shadow price just below the commitment price of the resource that would otherwise operate at that same schedule (i.e., the resource they are displacing).

POOLMod is a zonal transportation based model, giving it the ability to take into account thermal limits across pre-defined zones on the transmission network.