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Alberta Electricity Transmission Policy for the Next Generation

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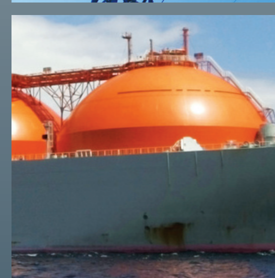

Alberta Electricity Transmission Policy for the Next Generation

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Executive summary

Electricity generation in Alberta was deregulated by the Electric Utilities Act of 1995. The act established the market where electricity producers, marketers, importers, distributors, exporters, and large industrial consumers could sell and buy electricity, and which now determines wholesale electricity prices. Electricity transmission and distribution continued to be regulated because it was generally accepted that effective competition was unattainable in these cases since having parallel, competing systems would result in considerably higher unit costs.

Prior to deregulation, the Energy Resources Conservation Board regulated not just transmission (the delivery of power at high voltage from generators to substations) and distribution (the delivery of power from substations to most consumers), but electricity generation, too. When generation was deregulated, the government was challenged to ensure that transmission facilities would be expanded more or less in step with generation capacity, something that had been pretty much assured by the former integrated planning process. This led, in 2003 and 2004, to the development of policies and regulations that require the Alberta Electric System Operator (AESO) to seek the approval of the Alberta Utilities Commission to upgrade and extend the transmission system in a timely manner so as to ensure that Alberta's electricity generators are not constrained from supplying energy to the system by insufficient transmission capacity and what is referred to as "transmission congestion."

Present transmission policy provides no incentive for new generators to consider the impact on transmission costs when planning where to situate new plants. (The system contribution payments that new generators must make have no effect because the amounts are insignificant and, in any case, are eventually refunded.) Further, in exercising its mandate to expand the transmission system (i.e., facilities energized at the 138 kilovolt level or higher), the non-profit AESO has no incentive whatsoever to seek cost-effective solutions. Without policy changes, transmission costs are bound to be become a much greater burden on Alberta's electricity consumers than necessary.

Reforms are necessary to ensure that changes to the transmission system are based on economic considerations. This report recommends that:

- Responsibility for planning the province's transmission system requirements be moved from the AESO to the transmission facility owners who have an intimate knowledge of the system. As in the United Kingdom, the private sector, not the government, should determine how the transmission network is developed. (The Alberta Utilities Commission would serve as arbitrator, ensuring that capacity isn't added unnecessarily.)
- Competitive bidding for the construction, ownership, and operation of transmission lines be introduced in order to minimize costs.

- Provincial transmission policy be revised to ensure that the most economic remedies to transmission congestion, including non-wires solutions when warranted, must always be sought.
- Marginal loss pricing methodology be introduced in order to assign the actual costs of transmission losses directly to the generation facilities that provide energy to the transmission system. This would ensure that investors considering new generation facilities pay close attention to potential transmission losses when selecting plant location.
- Finally, system contribution payments by, and transmission loss charges to, electric generators should be eliminated as there is no evidence that these factors are affecting investors' decisions with respect to the location of new generating stations.

Introduction

The Alberta Electric Utilities Act was introduced in 1995, and deregulation of electricity generation in Alberta commenced on January 1, 1996.[1] An electricity transmission[2] policy was introduced by the provincial government in late 2003 and implemented the following year (Alberta Department of Energy, 2003a). The objective of the new policy was to ensure that there would be sufficient transmission capacity to meet the needs of the competitive wholesale electricity market and to attract investment in new electricity generating facilities.[3]

Prior to deregulation, the Alberta electricity sector was dominated by several large companies that were each involved not only in electricity generation, but also in transmission and distribution services: TransAlta Corporation, ATCO Electric, and EPCOR (formerly City of Edmonton Power). The provincial Energy Resources Conservation Board (ERCB) regulated rates, facilities construction, and system improvements. Integrated electricity system planning ensured that transmission capacity was expanded in step with generating capacity.

Prior to 1996, attempts had been made to eliminate the differences in regulated electricity rates between the northern and southern regions of the province (Alberta Advisory Council, 2003).[4] With enactment of the Electric Utilities Act, uniform pricing of electricity was instituted at the wholesale level via the Power Pool of Alberta, which was established to match power supply with demand on a real time basis.

From 1998 through 2002, management of the transmission system was the responsibility of a for-profit transmission administrator. Today, the transmission system is the responsibility of the non-profit Alberta Electric System Operator (AESO).

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1 When electric generation was opened to competition, transmission (and distribution) remained regulated. It was generally believed that redundant transmission/distribution systems would not be economically feasible. The impracticality of parallel transmission lines has been demonstrated empirically (Salvanes and Tjotta, 1998)

2 Electrical transmission refers to the delivery of power at high voltage from generators to substations. Distribution is the delivery of power from substations to most consumers. In general, "transmission system" refers to facilities energized at the 138 kilovolt level or higher.

3 "Wholesale market" refers to the exchange of electricity among producers, marketers, importers, distributors, exporters, and large industrial consumers. "Retail market" refers to the purchase of electricity by small consumers (homeowners, businesses, and institutions) from electricity marketers or local distribution companies.

4 The differences arose mainly from the fact that the delivered cost of electricity from the large coal-fired generating facilities near Edmonton was lower in the north of the province than in the south where, mainly because of distance, the associated transmissions costs were greater.

Proposed expansions or upgrades must also be approved by the Alberta Utilities Commission (AUC), which came into being on January 1, 2008.[5]

The Greater Edmonton area has more electricity generating capacity than demand, while the opposite is true in the central and southern parts of Alberta, including Calgary (Alberta Department of Energy, 2003a). This situation has led the electric system operator to propose construction of a 500 kilovolt (kV) transmission line between Edmonton and Calgary (Alberta Electric System Operator, 2007a). The idea is to relieve congestion on the existing 240 kV line and to lower transmission losses, which were valued at $183.8 million in 2007 (Alberta Electric System Operator, 2007c: 52).[6]

Congestion occurs when the transmission equipment lacks the capacity to transmit all of the electricity needed to meet demand. Or, as characterized by the Alberta Energy and Utilities Board: “When the transmission system cannot accommodate all transactions that would normally occur due to physical or engineering limitations” (Alberta Energy and Utilities Board, 2002).

Congestion can be costly if lower-priced electricity generators are unable to access the grid while higher-priced suppliers do so elsewhere in the network.

When transmission congestion constrains power supplies, electricity generators may also be contracted to supply power under so-called “must-run” arrangements in order to maintain system reliability.[7] These orders raise transmission costs and also may mean that higher-priced electricity is dispatched instead of lower-priced power.

In its 2007 annual report, Alberta’s electric system operator forecast a doubling of electricity generation and consumption during the next two decades (Alberta Electric System Operator, 2007c: 14). The forecast was based on expectations of continued expansion of the Alberta economy and population growth. Even with less rapid growth, the transmission infrastructure will need to be upgraded and expanded to ensure sufficient capacity to meet demand. For this reason, we have reviewed key aspects of current policy and recommend reforms to ensure that transmission capacity is sufficient and that congestion can be managed more efficiently than under the present legislation.

5 The Commission consists of up to nine members appointed by the government, one of whom is designated as chair (Alberta Utilities Commission Act).

6 The loss of power during transmission occurs when the current of charged electrons moving through the transmission cable comes into contact with atoms in the cable itself. The value of transmission losses actually declined in 2007 because the hourly pool price that is used to establish loss value declined considerably, on average. In volume terms, the 2.87 terawatt hours of energy that were lost in the transmission process during 2007 was about the same volume as in 2006.

The 500 kV rating of the proposed transmission line would help to reduce transmission losses because they decline as the voltage at which the electricity is transmitted increases. This is because with higher voltage less surface area is required (Energy Vortex, 2008).

7 Annual “must-run” costs amounted to $45.6 million in 2007 and $41.3 million in 2006 (Alberta Electric System Operator, 2007c: 52).

Development of Alberta's transmission policy

In 1999, the transmission administrator proposed a methodology known as "system expansion related pricing" (SERP) to ensure that the electricity generators would make sufficient payments to cover the costs of upgrading and expanding the transmission system. Under the proposal, charges would be levied monthly based on the location of each power plant and the volume of electricity that it supplied to the transmission system. Proponents maintained that this approach would provide an incentive to locate new generating facilities closer to areas where demand was growing and thus relieve the strain on the transmission system. Otherwise, it was expected that the major operators of coal-fired facilities near Edmonton would add capacity at their existing sites.

SERP was not implemented because it was viewed as a "highly-complex, super-nodal, highly individualistic" method of allocating costs (Alberta Energy and Utilities Board, 2002). Also, the Energy and Utilities Board regarded the proposed zone-based cost structure as too complex to be workable (Alberta Energy and Utilities Board, 2000a).

Following the rejection of the SERP approach, in 2000 the transmission administrator issued another proposal to promote the siting of power plants closer to areas where demand was greatest: location based credits standing offers (LBCSOs) (Alberta Energy and Utilities Board, 2000b). The idea was to offer "credits" to generators that located in areas where additional power supplies were needed in order to maintain system reliability.[8] This approach was designed to reduce the need for costly additions to the north-south transmission grid.

This credit system, when applied, meant some departure from the market rates for the few generators that were involved. Additional remedies also were deemed necessary to ensure that there would be sufficient voltage to meet reliability requirements, including operating reserves, black start, and other system supports (Alberta Energy and Utilities Board, 2000b).[9]

Similar to the system of location-based credits was a program called "invitations to bid on credits" (IBOCs). This was implemented as a solution to the perceived lack of sufficient electricity generation in the Calgary area. Potential investors in new generating capacity were invited to submit bids and, in return, were granted a fixed credit

8 Essentially, generators received "credits," or extra payments per unit of power produced beyond the applicable market-clearing price.

9 Operating reserves are stand-by capacity that is kept online in case the power system suffers a severe strain and reserve power is required. "Black start" is the procedure needed to recover from a total or partial shutdown of the transmission system which has caused an extensive loss of supplies. This involves individual power stations being started and gradually reconnected.

(additional payment) per MWh of energy supplied for the life of the plant. In 2000, credits were awarded to three projects involving a total of 281 MW of capacity that commenced service in late 2001 near Cavalier, Carseland, and Balzac. The credits equaled \$3.25 per MWh, \$3.75 per MWh, and \$3.75 per MWh, respectively (Alberta Energy and Utilities Board, 2000c).[10]

In November 2002, the Energy and Utilities Board considered yet another approach, known as "locational marginal pricing." This system was designed to capture the incremental cost of congestion resulting from adding electricity to the grid.[11] Consequently, electricity prices would be highest in congested areas because the costs of delivering electricity to such areas would be higher.[12]

The Energy and Utilities Board rejected locational marginal pricing for three reasons: uniform pricing for all consumers throughout the province would not be possible; administering the pricing regime would be too complex; and there were doubts that the approach would be effective (Alberta Energy and Utilities Board, 2002).

Still intent on swaying siting decisions, the board later directed the system administrator to levy "zonal interconnection charges" that would vary depending on where a new power plant was located. Electricity generators in zones where supply exceeded demand would face higher charges because of the board's preference for steering power plants to locations where there was a shortage of generating capacity (Alberta Energy and Utilities Board, 2002).

The zone charges were never implemented because the Alberta Department of Energy, in early 2003, determined that it would be inconsistent with its policy of "unconstrained" transmission. As noted by the minister of energy, the Honourable Murray Smith, "Alberta … transmission infrastructure will not be a barrier to the development of new generation" (Independent Power Producers Society of Alberta, 2003).

In 2004, following consultation with various stakeholders, the province adopted the Alberta transmission regulation (Alberta Department of Energy, 2003a). The regulation embraced an "off-tariff" approach to steering new generating facilities to high-demand areas. The incentives took the form of "system contribution payments" and "loss charges."[13] "System contribution payments" are one-time charges to new

10 If the wholesale price were to average \$60 per MWh, a credit of \$3.75 per MWh would increase the operator's revenue by 6.25 percent.

11 The marginal or incremental congestion cost would be the cost imposed on the operator to manage the increase in congestion including, for example, a share of the cost of transmission must-run arrangements.

12 A number of US independent system operators (ISOs) are using locational marginal pricing, including those in New England, New York, the Pennsylvania/New jersey/Maryland network, the Midwest ISO, and the Southwest Power Pool. Zone pricing has been introduced in California and Texas.

13 System contribution payments and loss factor charges are known as "off-tariff" mechanisms because they do not affect the wholesale electricity price directly and are not included in the regulated transmission tar-

generators that vary depending upon the plant location in relation to the transmission system. The payments ultimately are refundable. Loss charges are based on a generator's average impact on transmission losses, and are adjusted annually.

Under this policy, customers bear most of the actual costs of transmission regardless of the location of generating facilities. The policy underscores the principle that the prices of electricity in a competitive wholesale market must not be distorted by the costs of transmission.[14]

Shortcomings of current transmission policy

1. Absence of locational signals

The current transmission policy incorporates a principle of "zero" congestion.[15] Indeed, the electric system operator is required to eliminate congestion by ensuring adequate, timely expansion and upgrading of the transmission system.[16]

Zero congestion policy is flawed. Just as building a 20-lane highway to eliminate all traffic congestion would be inefficient, constructing transmission lines to eliminate all congestion is uneconomic; the marginal cost of eliminating all congestion is greater than the marginal benefit of doing so.

It is economically beneficial that transmission policy address the location of electricity generating facilities in order to ensure that the delivered cost of electricity is as low as possible. If generators' siting decisions ignore the impact on transmission costs, the combined cost of energy and transmission will be less than optimal. In fact, siting decisions made without regard to transmission costs almost certainly would necessitate transmission system upgrades or expansions that could otherwise be avoided. For example, "non-wire" solutions, such as building generating facilities closer to areas of growing demand, could minimize the combined costs of electricity production and transmission. Clearly, current transmission policy is not in the best interests of Alberta

iff. Loss factors are applied by the system operator to each electricity generator's production to calculate charges for transmission system losses. A locational "signal" provides an incentive to generators to choose a location which will minimize the transmission system costs.

14 Essentially, this rules out the locational marginal pricing approach.

15 Under "zero" congestion, the intent is to ensure that the electric system is not constrained by insufficient transmission capacity during periods of peak demand.

16 The electric system operator is responsible for ensuring that there is sufficient transmission capacity. This involves anticipating where new power generating facilities will be sited, and upgrading and expanding the system to accommodate additional traffic without congestion.

electricity consumers because it does not consider the possibility of lower-cost alternative solutions.[17]

Under current policy, transmission costs are insignificant in siting decisions. The one-time "system contribution payments" for new electricity generators range between $10,000 and $40,000 per MW of installed capacity. The charges are higher for locating in areas with more generating capacity than demand, and lower for locating in areas with a shortage of generating capacity. However, in relation to the multi-million dollar cost of a new power plant (TransAlta Corporation, 2007),[18] the payments are of little consequence. Moreover, they are refunded within 10 years of the plant's "satisfactory operation" (Alberta Department of Energy, 2003a).[19]

The assignment of loss factors does not ensure that the costs of electricity generation and transmission will be lowered; the system operator does not consider loss factors when deciding which electricity to transmit.

In figure 1, electricity from Generator A would be dispatched first because the cost of the power offered is less — even though transmission losses and the delivered cost of the energy would be greater than that of Generator B.[20]

By way of summary, the system contribution payments have no meaningful impact on siting decisions. Further, transmission loss charges are generally too small to affect siting decisions and therefore don't steer the siting of new power plants to locations where transmission costs would be lower. Lacking any real incentive to consider transmission costs in their siting decisions, generators are unconstrained from locating far from areas experiencing growth in demand.

2. Planning and building new transmission

Current policy requires the Alberta Electric System Operator to obtain approval for transmission system upgrades or expansion from the Alberta Utilities Commission (Alberta, 2007c, Alberta Regulation 86). The application must indicate how the proposed changes conform to the system operator's 10-year plan and 20-year outlook.

The system operator need not take cost into account when deciding upon transmission upgrades or expansion. The only requirement is to ensure that transmission

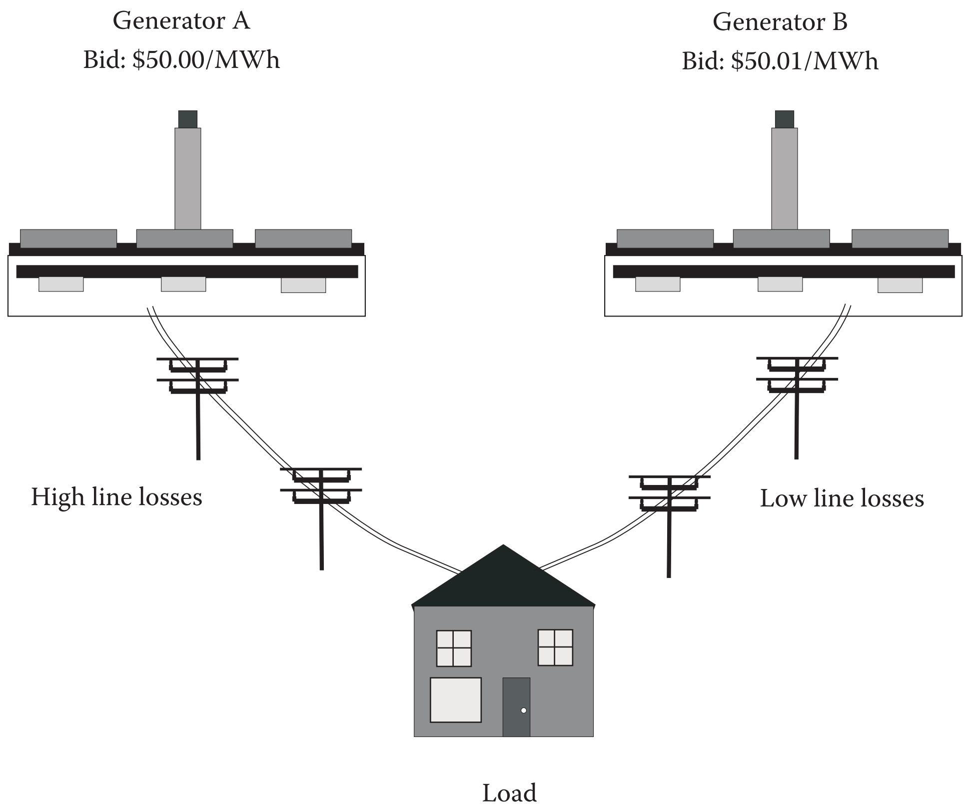
17 This issue is also discussed in a recent paper by ENMAX Corporation (ENMAX, 2008).

18 For example, the TransAlta Corporation/EPCOR coal-fired generation facility at Keephills that is under construction is projected to cost $3.55 million per MW of installed capacity.

19 In practice, "satisfactory" operation simply means having the generator available.

20 An additional difficulty with loss factor charges is that their calculation has proven to be a contentious issue, resulting in costly stakeholder consultation processes and hearings.

Figure 1: Electricity dispatches and transmission losses



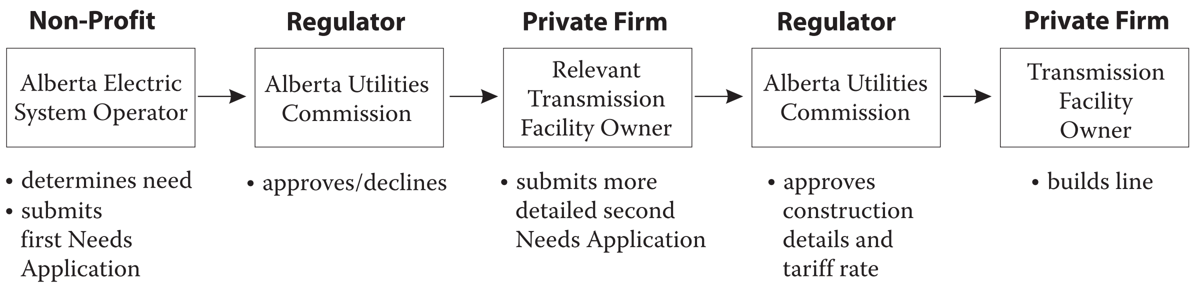
capacity is adequate "to meet the forecast load, imports and exports of electric energy, and anticipated generation capacity, including appropriate reserves" (Alberta, 2007c, Alberta Regulation 86).

Once a proposal is approved by the Utilities Commission on the basis of need, the system operator decides who is eligible to build and operate the new infrastructure in accordance with section 35.1 of the Electric Utilities Act. The eligible applicant must obtain approval to construct the transmission facility from the Utilities Commission. This two-stage approval process is unnecessarily time-consuming and costly.[21]

For example, a new 500 kV line between Edmonton and Calgary was originally proposed on May 19, 2004. However, the Alberta Energy and Utilities Board did not

21 According to section 15.4 of the Hydro and Electric Energy Act, the Utilities Commission may now combine and consider at the same time both the needs application filed by the system operator and a submission by a company proposing to construct a new transmission line. However, the fact that two parties would still be involved before the commission on essentially the same matter adds to the time, cost and difficulty of getting a new facility approved.

Figure 2: The Alberta transmission facility approval process



approve the initial application for nearly a year. As a result of this and other regulatory delays, the estimated capital cost of the project increased by at least 76 percent, from $300 million in 2004 to $528 million in 2007 (Alberta Electric System Operator, 2007b: 6).[22]

As a non-profit organization, the system operator has no incentive to ensure that new transmission is built in a timely or efficient manner. Moreover, as a creation of government, the organization is prone to political pressures.

In contrast, a for-profit transmission administrator would likely minimize operating costs and be less susceptible to political pressures (Boyce and Hollis, 2005). Between 1998 and 2002, for example, ESBI Alberta Ltd. served as the transmission administrator, with a mandate to provide "fair and open access" to the province-wide transmission system (EirGrid, 2008).[23]

The United States has experienced similar regulatory problems as numerous non-profit regional transmission organizations have recently emerged in that country. The principal problem is accountability; without the ownership of assets, a non-profit transmission organization does not absorb the costs of inefficient or imprudent decisions. Instead, these costs are passed directly to consumers. Consumers, in turn, cannot readily participate in the consultation process because doing so is technical and costly (Dworkin and Goldwasser, 2007).

The drawbacks of current transmission policy favor reforms that would allow transmission congestion to be considered in siting decisions. In addition, reforms would help to ensure that upgrades to and expansion of the transmission network would be achieved in a timely and efficient manner.

22 This does not take into acccount the cost of unrelieved congestion that on occasion has prevented some generators from supplying energy to the grid and thus raised electricity prices.

23 It is unclear why ESBI Alberta Ltd.'s five-year contract was not extended.

Recommendations for policy reforms

The following suggestions need not be implemented simultaneously.[24]

1. Allow owners of transmission facilities to plan expansion

As previously noted, the Department of Energy regards the elimination of congestion as the primary objective of network planning. However, it would be more economically rational to eliminate congestion only when the benefit of doing so exceeds the cost. Moreover, construction of transmission facilities should be undertaken when less costly alternatives (i.e., non-wire solutions) are unavailable.

Scott Thon, the president and CEO of AltaLink, who has an obvious interest in expanding the company's rate base, believes that transmission capacity needs to be increased as a result of 20 years of neglect (Thon, 2005). This claim is not in dispute. In fact, the only major transmission line built in the past 20 years, from Fort McMurray to Northeast Edmonton, was completed in 2004 (Alberta Electric System Operator, 2007a). However, as previously noted, upgrading and expanding the transmission system is not the only means of reducing congestion.

Owners of transmission facilities, who manage the operation and maintenance of the network, are the most knowledgeable about network capacity. Optimally, they should play a major role in infrastructure planning.

At present, there are two primary transmission facility owners in the province: AltaLink and ATCO Electric. AltaLink, with its network in central and southern Alberta, is the larger of the two, encompassing about 55 percent of the network in the province. ATCO Electric owns about 42 percent (Thon, 2005).

Any transmission network owner who also holds a stake in an electricity generating facility, such as ATCO Electric, should be required to erect a "firewall" between the two divisions if allowed to participate in transmission planning. That's because transmission planning requires the solicitation of proprietary information from generators.

There are a number of potential benefits to authorizing transmission network owners to plan system enhancements and expansion. Unlike the provincial Electric System Operator, the owners of the transmission networks have every incentive to expedite planning and thus infrastructure improvements. In privatizing the planning, a secondary check on network owners would be useful to ensure that they do not expand capacity simply to increase their revenues. The utilities commission could perform that function.

24 For example, we suggest that the system operator solicit competitive offers, including non-wire solutions, to congestion-related problems. This is not necessarily consistent with another suggestion which we put forward, that of requiring the transmission facility owners to plan expansions.

Such an arrangement exists in the United Kingdom. National Grid Co[25] and other owners of transmission facilities submit upgrade and expansion plans to the government's Office of Gas and Electricity Management. The agency reviews the proposals and sets transmission tariffs for five-year periods. However, it does not prescribe the development of network capacity (Office of Gas and Electricity Management, 2009).

2. Require competitive bidding for large contracts

Once a transmission plan is finalized, the utilities commission should be required to initiate competitive bidding for construction, ownership, and operation of a new line. Doing so would help to minimize costs.

3. Encourage alternative remedies to congestion

As previously noted, the electric system operator is essentially required to regard expansion of the transmission network as the sole remedy to congestion. But more efficient alternatives may be available. For example, locating generating facilities in areas where electricity supply lags demand could avoid costly construction of additional network capacity. Meanwhile, energy efficiency measures could slow the growth of electricity demand, thereby reducing transmission congestion.

4. Implement marginal loss pricing

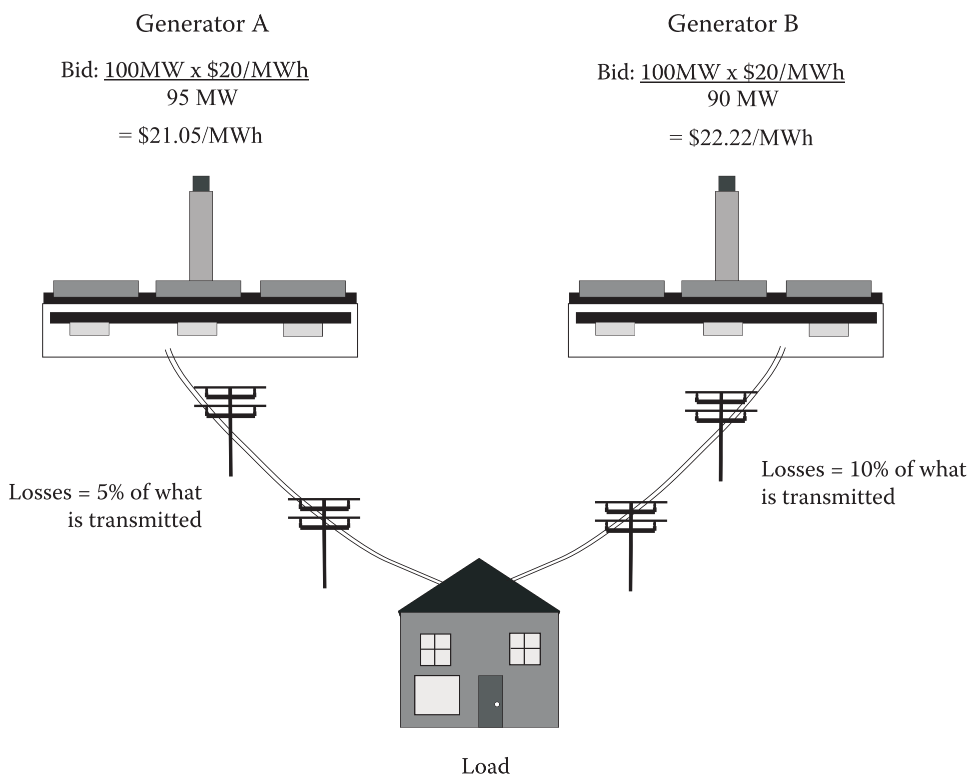
Marginal loss pricing is a method of accounting for the cost of transmission losses in the market price of electricity. Thus, it determines, in real time, the true cost of power supplies and helps to ensure that power that is truly the least costly is transmitted.[26]

In the example shown in figure 3, the bids of Generators A and B are identical and, under the current system, would be considered equally in determining the timing of transmission. But dispatching Generator A's power first is economically preferable because the combined cost of electricity production and transmission loss would be lower. In terms of cost per MWh, the effective offer of Generator A is (100 MW x \$20/MWh)/ 95 MW=\$21.05/MWh while that for Generator B is (100MW x \$20/MWh) / 90 MW=\$22.22/MWh.

25 National Grid is one of the world's largest utilities with transmission assets in Europe and North America (National Grid Company, 2009).

26 In March 2003, it appeared that the Department of Energy was leaning towards the implementation of this approach (Alberta Department of Energy, 2003b).

Figure 3: Marginal loss pricing



Marginal loss pricing was implemented recently in the Pennsylvania/ New Jersey/ Maryland transmission network and is expected to yield $100 million in annual cost-savings (Pennsylvania Jersey Maryland, 2007). Of course, the cost-savings would not be as great in the smaller Alberta transmission system, but substantial savings could still be realized.

Opponents claim that marginal loss pricing contributes to price volatility and, unlike fixed loss factors, increases the risks of investment in new power generation. Generators, for example, expressed a desire for fixed loss factors to satisfy their financing requirements (ESBI Alberta Ltd., 1999). While this may be true, consumers should not have to pay higher rates for electricity to shield private investors from risk.

5. Eliminate system contribution payments

System contribution payments are ineffective in influencing the siting of generating facilities. As noted previously, such charges are insignificant compared to other costs and are eventually refunded. Consequently, they serve no real purpose, and should be eliminated.

Conclusion

Since the deregulation of electricity generation, the efficient planning of transmission capacity has proved challenging for regulators and policy makers. The Alberta Department of Energy has pursued a "congestion-free" policy that fails to weigh the costs and benefits of alternative solutions. Furthermore, transmission planning is controlled by a non-profit group that lacks accountability and accurate information about current market conditions. The electric system operator lacks a stake in both cost reduction and timeliness.

Transmission policy should harness the power of economic incentives to minimize costs and maximize efficiency. Proposals for expanding transmission capacity should encompass a variety of approaches, including "non-wire" solutions to congestion.

Current law allows the electric system operator to delegate the preparation of some planning documents to owners of the transmission network. But this dances around a much more efficient solution, i.e., stripping the system operator from planning responsibility altogether. Instead, network owners are both thoroughly capable of planning and are better equipped to plan for capacity upgrades and expansion.

Introducing competitive bidding for construction projects also would help to control costs. System contribution payments should be eliminated; they do not provide locational signals as intended.

Finally, implementing marginal loss pricing would assign the actual costs of transmission losses to generators. In so doing, potential investors in new generating facilities would be compelled to consider transmission costs when deciding on a location.

As the Alberta economy grows, demand for electricity will increase and so will the need for more generating and transmission capacity. To the extent that current policy inhibits efficient expansion of the network, customers will pay more than necessary for electricity, and the province will be a less attractive place for investment and job creation.

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Gerry Angevine is Senior Economist in the Fraser Institute's Centre for Energy Studies. Since joining the Institute in July 2006, he has written two studies on Ontario electricity policy issues, including a critique of the government's central-planning approach to determining future electricity supplies. He has also written on labour mobility issues affecting Canada's energy sector, the economics of a proposed carbon dioxide "backbone" pipeline in Alberta, issues pertaining to carbon allowance trading, and the merits of "P3s" for relieving municipal infrastructure financing pressures in Alberta's oil sands region. He is presently coordinating a series of studies on the development of a continental energy strategy, and he also manages the Institute's annual Global Petroleum Survey.

Dr. Angevine served as a Managing Consultant with Navigant Consulting Ltd. from 2001 to 2004 and has been president of Angevine Economics Consulting Ltd., an energy economics consulting firm, since 1999. He was president, CEO, and a director of the Canadian Energy Research Institute from 1979 to 1999. Prior to that, he worked as an economist at the Canadian Imperial Bank of Commerce and the Bank of Canada.

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