The BC – Alberta Intertie: Impact of Regulatory Change

By

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June 16, 2004
This paper was presented at the Insight Conference, 4th Annual Alberta Power Summit held in Calgary, Alberta on February 12 & 13, 2004

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Introduction and Background

The electric systems of Alberta and British Columbia are interconnected through a 500kV line between Cranbrook, British Columbia and Langdon, Alberta, and two 138 kV transmission lines between Natal, British Columbia and substations at Pocaterra and Coleman, Alberta. While loop flows can occur so that power flows one way on the 1 x 500 kV line and the other way on the 2 x 138 kV lines, all three are treated for operational purposes as a single line. For the purpose of this discussion, these interconnections will be referred to collectively as the Alberta-BC Interconnection, or the Intertie.

The Cranbrook-Langdon 500 kV line was completed in 1986. The British Columbia portion of it is owned by BC Hydro and Power Authority (BC Hydro), and operated by the new BC Transmission Corporation (BCTC), while the Alberta portion of it is currently owned by AltaLink and operated by the Alberta Electric System Operator (AESO).

The two 138 kV lines were built by Kanelk Transmission Company Limited in the 1950s, originally to serve customers and mining operations located in the Kananaskis and Elk Valley regions. Since 1999, the British Columbia portions have been owned by BC Hydro, and they are currently operated by BCTC. The Alberta portions are owned by AltaLink and operated by the AESO.

The AESO and BC Hydro are parties to an Interconnection Agreement establishing the terms and conditions for operating the interconnection between the Alberta Control Area and the B.C. Control Area.[1] The control area boundary metering points are at Langdon and Pocaterra, Alberta and Natal, B.C. for the Natal–Coleman line. BC Hydro is the Western Electricity Coordination Council (WECC) Path Operator for the Alberta-BC Interconnection.[2]

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[1] ESBI was the original counterparty, but the AESO, after its creation, became the counterparty by operation of law. We expect that BC Hydro will assign its rights and responsibilities under the Interconnection Agreement to BCTC. BCTC Real Time Operations System Operating Order 7T-17, BC-Alberta Interconnection, Effective August 1, 2003.

[2] AESO OPP 303 Alberta-BC Interconnection Management, at s.2.

Scheduling on the Intertie is coordinated between BCTC, which is responsible for interchange scheduling in B.C., and the AESO, responsible for interchange scheduling in Alberta. The schedule for the Intertie starts at hh:00 and ends at hh:60 – interchange schedule changes within the hour are not allowed except for system security reasons or the delivery of emergency energy.[3] Imports into Alberta must be offered in at $0.00 to the Power Pool and exports must be bid in at $999.99 in order to be dispatched. All imports and exports submitted by hh:30 in the implemented or conditional state are included in the interchange schedule for the next hour. Those submitted after hh:30 may or may not be approved depending on the AESO's ability to manage the request. If approved, those import or export blocks may be included in the interchange schedule for the next hour. Between hh:30 and hh:40, the transaction information is transferred to BCTC, and at hh:40, the AESO and BCTC confirm the net interchange schedule, the ramp start time and the ramp duration for the next scheduling hour.

The Alberta-BC Interconnection was designed to operate at an operating transfer capability (OTC) of 1200MW from BC to Alberta and 1000 MW from Alberta to B.C. These limits, based on normal system conditions with all transmission elements in service, were established and approved by the WECC.[4] Actual ratings on the Intertie are far below these limits, ranging from zero to 600 MW for Alberta to BC transactions, and 400-800 MW for B.C. to Alberta transactions. Additionally, rated capacity on the Intertie is often left unused even in circumstances where there is a meaningful difference in the market prices of Alberta and the Pacific Northwest. Both the lower-than-designed rated capacity and the under-use of that rated capacity are considered in this paper.

The primary reasons for the physical/operational limits on Intertie capacity are, in respect of exports from Alberta, voltage constraints within Alberta during high load periods arising from insufficient transmission reinforcement. In respect of imports into Alberta, the constraining factor is the single-contingency reliability criteria which limits the operating capacity of the

[3] AESO OPP 301 Alberta –BC Interconnection Scheduling.

[4] WECC Operating Transfer Capability Policy Committee, Approved 2003-04 OTC Limits, October 8, 2003; AESO OPP 304 Alberta-BC Interconnection Transfer Limits, Appendix 1, at s.1.1.

Intertie to the largest single capacity contributor from time to time, (plus incremental capacity of up to 400 MW due to Import Load Remedial Action Schemes when available).

Even apart from the physical and operational constraints on the Intertie, that capacity that is available is often under-utilized. An over-arching reason for this under-use is that regardless of Alberta supply and demand at any one time, there are numerous times in a year when it is simply uneconomic to schedule out of or into Alberta given market conditions in the Pacific Northwest (eg. better terms available at the California-Oregon border). A related factor is the different market structures in Alberta and BC. In BC, transmission users have explicit transmission rights, which must be purchased on an hourly basis, while in Alberta transmission rights follow dispatch of generation through Power Pool bidding. As well, importers into Alberta are price-takers (may only submit bids of $0.00), and are paid the after-the-fact price for the hour. In the result, importers into Alberta must hedge their Power Pool bids to take account of an after-the-fact price being lower than anticipated, and a committed transmission payment for delivery to the Alberta border.

One effect of Intertie capacity being left unutilized is higher wholesale prices both in Alberta and in the Pacific Northwest than would otherwise be necessary. Under-used transmission capacity is ultimately being paid for by ratepayers, as are the opportunity costs of market participants not having the necessary incentives to exploit wholesale price differences between markets.

1. **Regulatory Change in Alberta**

a. Consolidation of the Transmission Administrator, Power Pool Administrator and System Controller Functions

The role of Transmission Administrator was first created by the *Electric Utilities Act* of 1995, which introduced competition into Alberta's electric industry. The first Transmission Administrator, Grid Company of Alberta Ltd. (GridCo) was a joint venture between transmission system owners.[5] ESBI Alberta Ltd. was appointed as Alberta's independent Transmission Administrator in November 1997, and assumed the full duties of the Transmission Administrator on June 1, 1998. Historically, the Transmission Administrator was a "for-profit" organization responsible for planning the provincial transmission system, ensuring the reliability of the system, setting the rates for use of the system and ensuring fair and open access to the transmission system.

The Power Pool of Alberta was also created by the *Electric Utilities Act* of 1995 to operate the market through which all electric energy is traded in the province. The Power Pool performs the further key function of real-time coordination of the Alberta power grid. The Power Pool Administrator was established to administer the electric energy market, responsible for receiving bids and offers from Pool Participants, preparing the day ahead and 6-day forecasts, determining the merit order, and carrying out the financial settlement and reporting, while the System Controller was the real-time manager of the electric energy market and network operations, responsible for system security, voltage control, dispatching energy as per the merit order, scheduling interconnection transactions and managing system losses.

Transition towards a not-for-profit Independent System Operator (ISO) began in 2002. The new *Electric Utilities Act*[6], which came into force June 1, 2003, made key changes to Alberta's electrical industry structure, effectively integrating the functions of the Power Pool, Power Pool Administrator and System Controller with those of the Transmission Administrator into a single statutory corporate entity, the AESO. While electric energy in Alberta continues to be traded

[5] Atco Electric Ltd., TransAlta Utilities Corporation and EPCOR Generation Inc./EPCOR Transmission Inc.

[6] S.A. 2003, c.E-5.1.

through the Power Pool, the roles of the Power Pool Administrator and System Controller have been incorporated into the overall responsibilities of the AESO. The Power Pool Rules, Settlement System Code, Power Pool Code and Operating Policies and Procedures of the Transmission Administrator were consolidated into a single rules document in July, 2003, called the ISO Rules. While few substantive changes were made in the initial consolidation, the AESO has declared that it intends to affect a more substantive rewrite of the new ISO rules in the near future.

b. Alberta Energy's new Transmission Policy

The *Alberta Transmission Development Policy* paper (Transmission Policy)[7], issued by Alberta Energy on December 22, 2003 marks a significant shift in transmission pricing in Alberta, namely a shift to load-based pricing from the 50-50 load-generator shared pricing arrangement that has been in place since 1999. At page 3 it states in unequivocal terms that "Pricing and payment for transmission is fundamentally a cost most appropriately borne by the loads that are served by the transmission system, regardless of location".

The Transmission Policy does not indicate a fundamental change in market structure, and in particular does not indicate any move toward the implementation of explicit transmission rights or other features of FERC's *pro forma* Rule 888 Open Access Transmission Tariff, including congestion signals. Dispatch priority will continue to be based solely on energy bids placed through the Power Pool.

Significantly, the Transmission Policy also emphasises the need for transmission development in advance of load growth and generation development, which is to be initiated by the ISO through, among other things, planning studies, engineering and right-of-way acquisitions.[8] In addition, the Transmission Policy acknowledges that, because of the lack of firm transmission rights under the Alberta structure, it is important that the system be virtually congestion-free –

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[7] Alberta Energy Electricity Business Unit, Transmission Development – *The Right Path for Alberta,* A Policy Paper, November 2003.

[8] *Ibid.*, at p.7.

"95% of economic wholesale transactions can be realized without transmission congestion".[9] Again, the responsibility will be on the ISO to take the initiative to reinforce the transmission system sufficient to achieve this 95% target.

The Transmission Policy emphasises in several instances the importance of the Intertie to the effective functioning of competitive wholesale markets in Alberta. It specifically states that under normal conditions the Intertie ought to be capable of delivering, with suitable reinforcements and Remedial Action Schemes (RAS), about 1,000 MW from Alberta to BC, and about 800 MW from BC to Alberta. Under the Transmission Policy the cost of these reinforcements and RAS will be allocated to Alberta load[10], consistent with the Transmission Policy's general assertions regarding load-responsible transmission fees.

The Transmission Policy also makes an interesting reference to the BC Hydro transmission system, stating at page 9 that "a combination of market design and exercise of market power have constrained the use of inter-ties through BC." The concept implicit in this statement is that the Intertie is not simply the 1 x 500 kV and 2 x 138 kV transmission lines referred to as the Intertie in this paper, but rather the entire BC Hydro transmission system from Alberta to the point of interconnection with the Bonneville Power Administration system in Washington State. Without commenting on the merits of this perception or the articulated reasons for it, we hypothesize below that changes on the BC side of the border arising from the implementation of new energy policy ought to go some way towards making the assertion less true than it currently is.

c. Enhanced Role of Market Surveillance Administrator

The new legislative regime brought into force in June 2003 also brought about an expanded role for the Market Surveillance Administrator (MSA). Under the old legislation, the Power Pool Council (PPC) was charged with monitoring the performance of the Power Pool and ensuring the promotion of an "efficient, fair and openly competitive market for electricity" in Alberta.[11]

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[9] *Ibid.*, at p.8.

[10] *Ibid.*, at p.9.

[11] *Electric Utilities Act*, R.S.A. 2000, c.E-5, s.9(1).

The Minister designated one of the members of the PPC as the MSA.[12] While the MSA performed the bulk of the legislated surveillance duties, the PPC was not precluded from carrying out the same surveillance duties and functions.[13] The MSA was required to make recommendations and prepare a report to the PPC at the completion of each investigation,[14] upon which the PPC could accept, modify or reject any of the recommendations, hold a hearing or impose any fines or order other sanctions.[15]

Now a separate corporate entity with a distinct governance structure, the MSA has broader (and exclusive) responsibilities under the new Act. The PPC has been eliminated entirely, and the MSA is charged with sole responsibility for carrying out surveillance and investigation of the electricity market to ensure the "fair, efficient and openly competitive operation of the market".[16] The MSA is also exclusively charged with assessing whether or not the ISO rules facilitate the "fair, efficient and openly competitive operation of the market", and are sufficient to discourage anti-competitive practices in the electric industry.[17]

While it was always part of the MSA's mandate to monitor and investigate electricity exchanges on the tie lines connecting the AIES with electric systems outside Alberta, there now exists increased discretion in the exercise of these investigatory powers. It is for the MSA to decide whether to investigate the behaviour of market participants. The Act does not define the term "fair, efficient and openly competitive". If after a preliminary investigation the MSA is satisfied that the market participant has either contravened the Act, the regulations or the ISO rules, or has engaged in conduct that is not in accordance with the "fair, efficient and openly competitive operation of the market", the MSA may give notice to the chair of the AEUB requesting a Tribunal be appointed to investigate the matter further. This request of the MSA for the

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[12] *Ibid.*, at 9.1(2).

[13] *Ibid.*, at 9.1(3).

[14] *Ibid.*, at 9.4.

[15] *Ibid.*, at 9.5(1).

[16] *Electric Utilities Act,* S.A. 2003, c.E-5.1, s.49(3) ("*New EUA*")

[17] *Ibid.*

appointment of a tribunal must be accepted by the Chair of the Board, who is then required to establish a tribunal to investigate a matter. The Chair has no discretion to refuse a request of the MSA for the appointment of a tribunal.[18]

The new legislation also provides the MSA with increased access to and transfer of records from the ISO. The Market Surveillance Regulation[19] requires the ISO to make available to the MSA any records relating to market participants that are held by or become available to it pursuant to its mandate under the Act, and the MSA need not obtain consent of a market participant whose records have been obtained before using such records.[20] While the MSA must keep any records obtained pursuant to the Act or the Market Surveillance Regulation confidential and may only use the records for the purposes of the MSA's mandate[21], the legislation does not require any notice be given to a market participant that records relating to it have been requested by the MSA, or provide a threshold test for the MSA to satisfy itself prior to requesting such information from the ISO.

[18] *Ibid.*, s.61.

[19] Alberta Regulation 166/2003.

[20] *Ibid.*, at 2 and 4.

[21] *Ibid.*, at 5.

2. **Regulatory Change in British Columbia**

The British Columbia government released its new energy policy, "*Energy for Our Future: A Plan for BC*" on November 25, 2002 (the Energy Plan). Significant components of the Energy Plan that relate to Alberta-BC electricity trade include:

- the creation of the BC Transmission Corporation, an independent operator of BC Hydro's transmission system under the jurisdiction of the BC Utilities Commission;

- the development of a Heritage Contract between the generation and distribution arms of BC Hydro providing for the continued delivery of energy to BC ratepayers at embedded cost rates; and

- the development of retail access for large electricity consumers, coupled with a stepped rate for such customers, and various measures intended to enhance the development of the IPP sector in British Columbia.

Each of these components is discussed in more detail below.

a. Creation of BC Transmission Corporation

The Energy Plan calls for the creation of a new entity to independently operate BC Hydro's transmission system for the purpose of ensuring fair access for generators in British Columbia to the BC Hydro-owned transmission system, and for facilitating electricity trade generally.

Since 1996 BC Hydro has provided wholesale transmission service under a tariff that is materially identical to FERC's Rule 888 *pro forma* tariff. The administration of that tariff and the operation of BC Hydro's transmission system has been conducted by the Grid Operations (Grid Ops) division of BC Hydro. Grid Ops has always operated behind a "firewall", adhering to a code of conduct that prohibits the exchange of information between it and other divisions of BC Hydro and its marketing affiliate, Powerex Corp.

On July 25, 2003 the new *Transmission Corporation Act*[22] was brought into force, thereby initiating the development of an independent system operator in British Columbia. BCTC is a Crown corporation that will operate (but not own) BC Hydro's transmission system pursuant to agreements with BC Hydro. On November 20, 2003 a number of the essential agreements were designated by order of the BC Lieutenant Governor in Council thereby effectively deeming the new structure approved by the BC Utilities Commission.

The designated agreements envision a two-stage process to independent operation of BC Hydro's transmission system. During Phase 1, BCTC will administer BC Hydro's existing wholesale transmission tariffs, but will not directly provide transmission service itself. Phase 1 will culminate in a revenue requirement and rate design application by BCTC, expected sometime in the latter half of 2004. Following BCUC approval of new BCTC tariffs, Phase 2 will begin with the provision by BCTC of open access transmission service by the spring of 2005. In addition to new BCTC tariffs, wholesale transmission customers will continue to receive service from BC Hydro through owners' and asset management tariffs, but these new BC Hydro transmission tariffs will be designed, implemented and administered by BCTC.

The BC Hydro owners tariff is intended to recover, among other things, BC Hydro's debt service and depreciation costs, and a return on equity related to BC Hydro's ownership of the transmission system. The asset management tariff is intended to recover the BCUC-approved fee BC Hydro will pay to BCTC to maintain the transmission system. The BCTC tariffs will be designed to recover the cost of BCTC's operations, exclusive of the transmission ownership function. Collectively, these Phase 2 tariffs are referred to in the designated agreements as the Open Access Transmission Tariff (OATT).

Other significant elements of the arrangement are as follows:

(i) BCTC is to "seek to ensure that the terms and conditions of the OATT … meet the requirements of FERC … to the extent necessary to permit

[22] S.B.C. 2003, c.44.

continued access at market-based rates [in the U.S.] by electricity market participants in British Columbia";[23]

(ii) BCTC will be responsible for planning and developing the reinforcement and expansion of the transmission system, including applying for any necessary regulatory approvals;[24]

(iii) BC Hydro and BCTC have, with some limited exceptions, the express right to intervene in each others' proceedings, and in particular to take opposing positions;[25]

(iv) BCTC will have the exclusive authority for short-term system reliability, including the right to redispatch BC Hydro generation;[26]

(v) BCTC will be responsible for procuring interconnected operations services and providing ancillary services, while BC Hydro will in effect be a supplier of last resort to BCTC for interconnected operations services, and may self-supply ancillary services;[27] and

(vi) BCTC will succeed to all of BC Hydro's rights and obligations regarding RTO West.[28]

b. Heritage Contract

The Energy Plan calls for a legislated Heritage Contract that will preserve the benefits of BC Hydro's existing low-embedded-cost generation assets for BC ratepayers. Pursuant to the

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[23] Master Agreement between BC Hydro and BCTC at 4.5(b).

[24] *Ibid*., at 5.2 and 4.12(a).

[25] *Ibid*., at 4.14.

[26] *Ibid*., at 5.3 and 5.4.

[27] *Ibid*., at 6.2, 6.3 and 6.4.

[28] *Ibid*., at 10.1, 10.2 and 10.3.

Energy Plan BC Hydro filed a proposal to effect that goal with the BCUC in April 2003. A month long oral hearing in August, 2003 culminated in a report to the BC government from the BCUC and a government response, including new legislation, in November 2003.

Essential elements of the government response relating to the Heritage Contract were:

- The enactment of the *BC Hydro Public Power Legacy & Heritage Contract Act*[29], pursuant to which BC Hydro is prohibited from selling or otherwise disposing of its core generation, transmission and distribution assets; and

- The enactment of a new regulation, Heritage Special Direction No. HC2 (the Heritage Special Direction), with an attached Heritage Contract between BC Hydro's distribution and generation divisions. The Heritage Contract requires BC Hydro (generation) to deliver to BC Hydro (distribution) energy, capacity and ancillary services as required, up to a maximum of 49,000 GWhr per year, at embedded cost. The Heritage Special Direction requires the BCUC to set the rates of BC Hydro on the basis that the Heritage Contract is a legally binding agreement between the two arms of BC Hydro, and further requires the BCUC to set BC Hydro's rates on the basis that any energy deliveries from the generation to the distribution arms of BC Hydro in excess of 49,000 GWhr per year pass through to ratepayers at cost. Finally, the Heritage Special Direction requires the BCUC to establish two deferral accounts to carry forward into future rate periods variations between forecast and actual costs of providing the Heritage Electricity, and trade revenues.[30]

c. Stepped Rates and Retail Access

Along with the Heritage Contract proposal, and again pursuant to the Energy Plan, BC Hydro also filed proposals with the BCUC in the spring of 2003 for a stepped rate for large industrial and commercial customers, and the implementation of retail access for those same customers.

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[29] S.B.C. 2003, c.86.

[30] Subject, in the case of trade revenues, a floor of $0.00 and a cap of $200 million. Accounts below and above the floor and the cap are to be on account of BC Hydro's shareholder.

The BC government largely accepted the BCUC's recommendations arising from the hearing into the proposals, with the result that BC Hydro will file an application for stepped rates in late 2004 or early 2005 that incorporate the following features:

- the ratio of tier 1 energy to tier 2 energy should be set at 90:10, based on historic consumption levels;
- the tier 2 rate should reflect the long term opportunity cost of new supply; and
- the tier 1 rate should be derived arithmetically from the tier 2 rate;

In addition, the stepped rate is to be mandatory for all eligible (i.e. industrial and large commercial) customers. These design features are intended to ensure that stepped rates are margin neutral from BC Hydro's perspective (thereby avoiding cost-shifts to other customer classes) and revenue neutral to the eligible customers (ie causing eligible customers to pay no more than they pay under current tariffs for at historic consumption levels). A time-of-use rate option is also to be offered to eligible customers as an alternative to the stepped rate.

Government, in its response to the BCUC's recommendations, also implicitly accepted the recommendations that retail access for industrial and commercial class customers not be implemented until after BCTC has filed and received approval for its new WTS tariffs, and that BC Hydro has filed and received approval for retail access principles regarding the departure and return to utility supply. Thus retail access is unlikely to commence in British Columbia until 2005. However, with the tier 2 rate being set at the long-term opportunity cost of new supply, a number of Independent Power Producers (IPP) ought to be able to start selling directly to stepped rate customers.[31]

[31] Another related component of the Energy Plan is that BC Hydro will no longer build new generation (with some exceptions related to existing facilities). Instead IPPs are to be the suppliers of new BC-generated energy.

3. **Effect of Changes on Intertie Usage – Alberta**

The regulatory changes taking place in the Alberta electricity market referred to above are likely to have at least some impact on usage of the Intertie. Regarding the operational and physical limits on the use of the Intertie for Alberta exports, the focus of Alberta Energy's Transmission Policy on system reinforcement and development can only have a positive effect. Generators are more likely to generate for export where the costs associated with such export are to be borne by others – the Transmission Policy expressly refers to the cost of reinforcements and RAS, in the context of the Intertie, as being a load responsibility. To the extent that necessary upgrades can be made to the transmission system in a timely fashion, the Intertie constraints on Alberta exports ought to be relieved, at least to a certain degree. It remains to be seen the extent to which such constraints will be relieved, and how quickly they will be relieved.

The same is likely not true with respect to the operational and physical limits on imports, where it would appear that only by building new cross-border transmission or additional, very large generation in Alberta can the 800 MW actual capacity limit be increased. The implementation of the new Transmission Policy, the consolidation of functions under the roof of the AESO, or the enhanced role of the MSA are not likely to effect such a result.

Similarly, none of the regulatory changes undertaken to date are likely to affect the fundamental economics of making cross-border deals. Neither the consolidation of regulatory functions under the AESO nor the enhanced role of the MSA can address the regional market circumstances that will always simply make some cross-border transactions unattractive. While the Transmission Policy might have addressed some of the differences in market structures to minimize the tariff-based barriers to cross-border electricity trade, it simply does not. Instead, it assumes the continued operation of a unique Alberta market, making only a passing reference to the development of Regional Transmission Organizations and Single Market Design issues that continue to drive the evolution of market structures in other jurisdictions.

4. **Effect of Changes on Intertie Usage – British Columbia**

The creation of BCTC will, it is hoped, go some way to removing the concerns of a BC transmission system biased to favour BC Hydro's trading activities. Unlike in Alberta however, BC electricity policy, at least as expressed in the Energy Plan, has its eye firmly on US markets. Indeed, as noted above, BCTC is obliged under the Master Agreement to maintain a FERC-compliant OATT. Thus it is to be expected that BCTC will focus on coordinating its tariff and business practices to those south of the US border, as BC Hydro's Grid Ops has in the past. To the extent Alberta remains wedded to its unique market structure, the seams issues between the two provinces are unlikely to be resolved as a result of the creation of BCTC. Indeed, they may become more strained.

The Heritage Contract will not have any effect on utilization of the Intertie. By continuing with an embedded-cost rate structure in B.C. an opportunity to develop a robust wholesale market has perhaps been side-stepped. While the benefits are clear for B.C. ratepayers, they are not so clear for Alberta ratepayers.

However, the development of stepped rates, retail access and a robust IPP sector may in time lead to the development of a more robust bilateral wholesale market. The limiting factor here will be the relatively small amount of industrial load (10%) that will be put to market.

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