Energy Choice Matters

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Algonquin Power Fund Seeks CPCN for Merchant Line to Link Northern Maine, ISO-NE

Algonquin Power Fund (America) has petitioned the Maine PUC for a CPCN for a 345 kV transmission line running from Houlton, Maine to an interconnection with the Maine Electric Power Company (MEPCO) 345 kV line in Haynesville, Maine, to be known as the Northern Maine Interconnect. Algonquin said that the line will allow northern Maine generators to have improved market access, and will permit northern Maine customers to benefit from a competitive supply of energy from ISO New England, while improving the transparency and efficiency of the northern Maine market.

The Northern Maine Interconnect (NMI) will be built as a merchant transmission line and will provide, for the first time, Algonquin said, a direct electrical connection between northern Maine and southern Maine (and the ISO New England system). Construction of the Northern Maine Interconnect will permit an estimated 50 MW of firm south to north flow from ISO-NE to northern Maine, and an estimated 150 MW of firm north to south flows from northern Maine to ISO-NE.

"The NMI will thereby address, to a large extent, the concerns raised by the Commission and many parties about limited retail and wholesale competition in northern Maine. It will provide generation in northern Maine with a means to deliver wholesale energy to New England load and will also provide a means for wholesale supplies from southern Maine and New England to supply customers in northern Maine through open access on a transmission line that is under the jurisdiction

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CMP Opposes Customer Lists for Small Commercial and Residential Customers

Central Maine Power, "continues to oppose the idea of providing residential and small non-residential customer lists to CEPs [competitive electric providers]," CMP said in comments to the Maine PUC (docket 2001-399).

As only reported by *Matters*, Glacial Energy asked the Commission to direct the utilities to make customer lists of small volume customers available to suppliers (Only in Matters, 12/10/09). Currently, customer lists containing customer names and addresses are only available for the medium and large commercial and industrial classes at Central Maine Power and Bangor Hydro-Electric. In comments earlier this week, BHE said that it opposes residential customer lists except on an opt-in basis, but has no objection to small commercial customer lists (Only in Matters, 12/23/09).

"Contrary to previously stated difficulties of CEPs marketing to medium-sized customers, there has been no claim that marketing to small customers is inherently difficult," CMP said.

"Moreover, CMP does not see how such a claim could be substantiated. Marketing electricity to small customers should be no different than marketing any other product or service to such customers. For example, oil dealers are able to market their product to such consumers without the type of assistance at issue here," CMP added.

"There is simply no need for CEPs to have access to CMP's customer list for this size of customers. There are other widely-available methods for marketing to such customers, including radio, television,

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Ontario Board Denies Enbridge Request to Ratebase Non-Delivery, Renewable Investments

The Ontario Energy Board denied an application from Enbridge Gas Distribution to place the costs of renewable generation and other green investments into its gas LDC rate base, though the Board declined to answer the question of whether it has jurisdiction to include such costs in rate base (EB-2009-0172).

A Directive from the Ontario Minister of Energy issued in September expanded the activities which gas LDCs are permitted to conduct, aside from normal utility delivery operations, to include ownership and operation of certain conservation, demand management, and renewable energy generation investments. Enbridge applied to the Ontario Energy Board to place the costs of such "Green Energy Initiatives" into its gas rate base, calling such treatment consistent with achieving the province's renewable energy goals. Planned Green Energy Initiatives include solar, ground source heat pumps, distributed and District Energy systems, micro combined heat and power and heat from waste technologies, geo-thermal systems, and stationary fuel cell facilities.

In response, the Board determined that even if it does have the jurisdiction to include the costs associated with these programs in rate base, a finding that it explicitly did not make, it will not allow the Green Energy Initiatives to be included in rate base.

"There are a number of reasons why these investments should not be allowed in rate base. When assets are allowed in rate base it is generally because those assets are related to the monopoly franchise. Enbridge does not have a monopoly franchise for the production of renewable energy. Its franchise is related to the distribution of natural gas. To the extent that the Green Energy Initiatives involve activities for the production of renewable energy, they occur within a competitive market. Other participants would be materially disadvantaged were [rate-basing] to occur," the Board concluded.

"The same line of reasoning applies to the Green Energy Initiatives that do not directly involve the generation of electricity, but which take place within a broad competitive market involving the provision of a variety of new and refined products designed to facilitate the creation of an innovative conservation culture in Ontario. Permitting a well financed public utility to include its costs of participation in this market into its rate base, thereby transferring risk to the ratepayer, is unfair to other market participants," the Board added.

The Board stressed that including such investments in rate base would increase risks to ratepayers, rolling back ring fencing provisions first enacted in the 1980s.

Although the Minister's Directive allows the utility company to pursue investments itself, and not through a separate affiliate, the Board noted that the directive did not require the Board to place such investments in rate base.

Feed-in tariffs developed by the Board also provide a funding source for Enbridge's investments, making inclusion in the rate base unnecessary, OEB added.

For these reasons, the Board found that answering the jurisdictional question is unnecessary, as it would reject placing the green investments into rate base regardless of how it answered the question of whether it has authority to permit such rate-basing.

O&R Says Hourly Pricing Schedule Not Affected by Month Delay in Customer Usage Tool

Orange & Rockland reported to the New York PSC that the provision of a tool allowing customers to input hourly usage and pricing data to evaluate various scenarios has been delayed by about one month, but said that the delay will not affect its scheduled expansion of Mandatory Hourly Pricing scheduled to commence in May 2010 (Case 07-E-0949).

Pursuant to O&R's implementation plan to expand hourly pricing to customers with demands between 500 and 1,000 kW, O&R was scheduled to provide customers with a modified version of the EEM Suite in December 2009, which will allow customers to use hourly usage and pricing data to evaluate various scenarios, contingent on the development of a new Meter Data Management (MDM) system (Only in Matters, 6/29/09).

However, O&R informed the PSC that in developing the revised EEM Suite, it has experienced problems, particularly with the synchronization between different systems (particularly the billing system). This has resulted in a delay of approximately one month, and O&R now anticipates that the revised EEM Suite will be available to customers in January 2010. O&R plans to host required customer seminars in January 2010 regarding the new tool. Such seminars were originally scheduled for December.

O&R still expects to commence expanded hourly pricing in May 2010, as scheduled.

Constellation, BHE Enter Settlement on Errors Regarding Entitlement, Load Allocation

Constellation Energy and Bangor Hydro-Electric have entered into a settlement regarding erroneous uplift credits and various other errors under which Constellation will pay a net amount of about $162,000 to BHE.

The primary error relates to an entitlement agreement between BHE and Constellation, under which BHE sells to Constellation entitlements associated with its diesel generating units.

Under the original agreement, Constellation pays BHE both a capacity charge each month and an additional energy charge for fuel and variable O&M whenever the units actually operate. Although BHE sold all of the units' output, BHE retained the right to schedule the diesel units for local transmission support. When BHE exercises this right, BHE gives Constellation a credit toward the energy charges for the difference between the price Constellation pays BHE for energy and the value of the energy in the ISO New England market.

BHE subsequently learned that at the same time that it was providing Constellation with such credit for the out-of-merit dispatch, BHE was also billed for uplift by ISO-NE for exercising these same rights. In essence, BHE was paying twice for the exercise of the dispatch rights, once directly to Constellation, and again indirectly through the ISO-NE uplift charge. BHE called the ISO-NE uplift charge the appropriate treatment in such situations, and use of that charge to effect the credits is reflected in the latest entitlement contract. The revenue Constellation received from ISO-NE from uplift charges during the period BHE was also directly paying such charges to Constellation (March 2005 through July 2008) is approximately $139,000, which Constellation will refund to BHE under the settlement.

At the same time, BHE discovered that, for approximately the fourth month period of June through September 2008, when one of its medium Standard Offer customers moved to the Large class, BHE's computer system continued to attribute the customer's ICAP tag to the Medium class. Constellation was the supplier to BHE's Large Standard Offer class during this period, and was paid for the customer's load, but was not assigned the appropriate ICAP obligation (about 3.7 MW). While BHE was able to resettle the ISO-NE market back to October 2008, market rules prevented earlier resettlement, preventing BHE from refunding the appropriate amounts to the Medium class suppliers (Integrys Energy Services, Dominion Retail, and TransCanada Power Marketing) for the pre-October period. Thus, under the settlement Constellation would pay $73,000 to settle the ICAP obligation, permitting BHE to refund the amounts in the following manner: Integrys Energy Services, $43,000; Dominion Retail, $11,000, and TransCanada: $19,000.

Such charges to be paid by Constellation will be netted against errors that resulted in amounts owed to Constellation. For example, BHE discovered that two suppliers serving the Small Standard Offer class for the period March 1, 2005 through February 28, 2006 had incorrect load responsibility percentages attributed to them. Specifically the load of Independence Power Marketing (J. Aron) was reported to the ISO-NE market system as 33%, when it should have been 33.33%, while Select Energy (later Constellation) was assigned 67%, but should have been assigned 66.67%. This lack of granularity, arising from the billing system's original programming limits, resulted in about 2,600 MWh of retail sales for which Select was given load responsibility, but which should have been the responsibility of Independence. The total amount owed to Constellation under this error is about $32,000.

BHE also owes Constellation about $18,000 under the new process for compensating Constellation for the difference between the market price for the diesel units' energy when dispatched by BHE for reliability, and the price Constellation pays for the energy in the entitlement.

Netting these combined amounts results in a total of $162,678.24 to be paid by Constellation to BHE under the settlement.

Mich. Staff, Utilities File Settlement on PSC's M&A Authority

Michigan PSC Staff, Detroit Edison, Consumers Energy, several other utilities and several unions have reached a settlement that would define the transactions which constitute an acquisition, transfer of control, merger activity, or encumbrance of assets that are subject to MCL 460.6q, recent legislation which, for the first time, gives the Michigan PSC authority over utility mergers and acquisitions (U-15795).

Section 6q requires prior approval of the Commission for the following transactions:

(i) if a person acquires or merges with a jurisdictional regulated utility, or

(ii) if a transaction involves the transfer of control of a jurisdictional regulated utility, or

(iii) if a jurisdictional regulated utility sells, assigns, transfers, or encumbers assets to another person, except if such sale, assignment, transfer, or encumbrance of assets occurs in the normal course of business.

The settlement would define "asset" as real and personal property, including natural gas and electric distribution facilities, electric transmission and generation facilities, and natural gas transmission and storage facilities, owned by a jurisdictional regulated utility and used to directly provide natural gas or electric utility services to end users at rates regulated by the Commission. Under the stipulation, asset does not include accounts receivable.

"Normal course of business" would mean a transaction that is related to the transfer, sale, assignment, or encumbrance of assets which satisfies any one of several criteria. Among the conditions qualifying as the normal course of business (and not requiring Commission approval) would be, for utilities having 500,000 or more retail customers, a transaction that involves the transfer, sale, or assignment of assets having an original book cost equal to or less $50 million, if such transaction occurs prior to December 31, 2020. The dollar value threshold for the normal course of business would increase periodically under the settlement after 2020.

Additionally, for all utilities, a transaction, regardless of amount, would be considered in the normal course of business to the extent that the transaction constitutes a sale, assignment, transfer, or encumbrance of interests in fuel, natural gas, purchased power, electric or natural gas transmission capacity, natural gas storage services, or other commodities that is otherwise subject to review for reasonableness and prudence in a gas cost recovery or power supply cost recovery proceeding, or a successor thereof.

Regardless of whether the transaction meets the normal course of business standards above, the transaction shall not be classified as in the normal course of business if: (i) the transaction, either directly or indirectly, is in connection with the acquisition, transfer of control, or merger of a jurisdictional regulated utility, or (ii) the transaction involves the transfer or sale of an electrical generating plant that has a Total Installed Generating Capacity (nameplate rating) of more than 20 megawatts.

Briefly:

Senate Confirms Norris to FERC

The U.S. Senate has confirmed John Norris as a FERC Commissioner. Norris served as Chairman of the Iowa Utilities Board from 2005 to 2009. In 1999 and 2000 he was Chairman of the Iowa Electric Restructuring Task Force while serving as Chief of Staff for then Iowa Governor Tom Vilsack.

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of the Federal Energy Regulatory Commission," Algonquin said.

"The NMI will also enhance the opportunities for increased retail competition in northern Maine, making it easier and more efficient for retail suppliers serving load in southern Maine to participate in the northern Maine market," Algonquin added.

Algonquin further said that the NMI will provide a hedge against the uncertainty of energy supplies and/or transmission access through New Brunswick Power as a result of the proposed acquisition of NB Power by Hydro Quebec. A direct link to ISO-NE would provide transparent market signals for consumer pricing in northern Maine, and provide an outlet for new and existing generators, Algonquin added. The line will also promote renewable development, Algonquin noted.

Algonquin said that it plans to offer firm transmission rights in an open season process.

Algonquin stressed that the connection will not require the northern Maine utilities to join ISO-NE, but will create the opportunity to facilitate such membership if the PUC wishes to pursue it.

The NMI project would be constructed on 26 miles of existing right-of-way. Estimated cost of the line and associated substations is projected at $54 million.

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and newspapers. In addition, there is an entire industry dedicated to the development and rental of customer lists. Such lists are widely available for a nominal fee," CMP added.

Indeed, CMP referenced its comments regarding customer lists filed in 2001, in which it argued that, "[i]n order to fairly compensate T&D utilities for dealing with opt-out issues and for compiling and reviewing these lists for accuracy, it is appropriate to require that CEPs pay at least a nominal fee for customer lists. After all, we are dealing with sophisticated entities dealing in a competitive market. In a competitive market, marketers pay a fair price for mailing lists. As noted by the CEPs themselves at the July 12 [2001] meeting of interested parties, the lists maintained by T&D utilities are the best lists available, so it is common sense to that they should be willing to pay at least that which they would pay for a less complete list offered by a another entity."

"It is simply not reasonable for CEPs to expect to receive a valuable asset from each T&D utility and pay nothing in return," CMP stated.

CMP observed that since the Commission's 2001 order allowing medium and large commercial customer lists, "issues related to the privacy of customer information have grown with the increase in identity theft." CMP pointed to the PUC's finding in Docket No. 2007-71 that, at that time, Chapters 81 and 86 of its codes were silent on the confidentiality of customer records in the possession of a utility, and 35-A M.R.S.A. § 704(5) and Chapter 89 only addressed the treatment of utility customer information in the possession of the Commission.

"Therefore, nothing in [then] current statute or regulations prohibits a utility from sharing customer information. We believe that monopoly utilities should not be able to share customer information without the customer's consent. We therefore have added a provision that prohibits utilities from sharing customer information to a third party without the consent of the customer," the Commission said in Docket No. 2007-71, CMP noted.

In the event that the Commission does expand the availability of customer information to retail suppliers, "the Commission should impose serious penalties, including revocation of license, for abuse of the privilege of obtaining lists of T&D customers," CMP said.