Energy Choice Matters

July 15, 2010

N.Y. PSC Staff Recommends Lowering Hourly Pricing Cutoff to 250 kW at NiMo

Niagara Mohawk should be required to lower its cutoff for mandatory hourly pricing to 250 kW by the end of 2012, New York PSC Staff said in direct testimony in NiMo's current electric rate case (10-E-0050, Only in Matters, 2/1/10).

A threshold of 250 kW would be the lowest hourly pricing cutoff in the state, though Staff noted that the NiMo criteria for mandatory hourly pricing is stricter at than at other utilities. Specifically, to be defaulted to hourly pricing at NiMo, a customer must have six consecutive months of demand greater than the threshold, rather than a demand greater than the threshold in any two of the last 12 months, as is the case at some other utilities.

Staff reported that there are 1,179 billed accounts using approximately 1.9 billion kWh of electricity annually (approximately 30% of the annual SC-3 usage) at NiMo that have a demand level above 250 kW but below the current hourly pricing cutoff of 500 kW. Of those 1,179 billed accounts, 837 get their commodity from an ESCO, thus 342 full service customers would be switched to the hourly pricing tariff under the change.

Though customers above 250 kW on competitive supply would not be required to take hourly service, their ESCOs would be billed by the New York ISO for the customer's actual load instead of a class average hourly load shape, which, "will give ESCOs an incentive to develop time sensitive rates for their customers," Staff said.

Staff would maintain the current exemption from hourly rates in Special Provision L for customers receiving an allocation of NYPA power or who take service under the Empire Zone Rider.

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Md. PSC to Open POR Tariffs to Modification in Working Groups

The Maryland PSC accepted the Purchase of Receivables compliance filings of Baltimore Gas & Electric (both commodities), Delmarva Power & Light, and Allegheny Power with minor changes, but directed that working groups/technical sessions be held to address a host of concerns recently raised by Staff. Furthermore, the Commission, though not issuing any formal letter order yet, essentially indicated at its administrative meeting yesterday that anything in the POR tariffs would be fair game for modification in these new working groups.

Additionally, Delmarva said at the administrative meeting that it will be able to bill outstanding supplier receivables incurred prior to the start of POR on utility consolidated bills, after severe criticism from the Commission for its earlier indication that Delmarva would not be able to bill these arrearages on consolidated bills (see Matters, 7/2/10). There are about 280 supplier accounts which have outstanding arrearages which will not be purchased by Delmarva.

While Delmarva eventually committed to a utility consolidated billing solution for these pre-POR receivables using a manual solution, PSC Chairman Douglas Nazarian rebuked Delmarva for not adequately informing the PSC until its July 1 compliance filing that consolidated billing of these receivables could not be accomplished (until acquiescing to a manual solution yesterday).

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Briefly:

Pepco Updates POR Transition Plan

Pepco has updated its transition plan for its Maryland Purchase of Receivables program, which it has asked to be effective September 1, 2010. Among other modifications from its original plan (Only in Matters, 7/2/10), Pepco will now be implementing a structural change to the 820 transaction as part of POR. Pepco will include the original amount, the discount amount, and the discounted amount (e.g. payment amount) in the 820. Previously, Pepco said that it would only include the payment amount in the 820. The updated transition plan also includes more details regarding procedures for instances where usage is cancelled (Maillog 123996).

NYSEG/RG&E Joint Proposal Would Add Costs to POR Discount Rate

Parties have filed a joint proposal in the electric and gas rate cases of NYSEG and Rochester Gas and Electric (09-E-0715 et. al.) that would add commodity-related credit and collections costs, and a portion of call center costs, to the POR discount rate.

Under a stipulation between Staff and the utilities which is part of the joint proposal, the POR discount percentage would be comprised of the following components: commodity-related uncollectible costs, a financial risk adder, and commodity-related credit and collections and call center costs. As previously reported, all retail access customers, even those on utility consolidated billing, currently avoid commodity-related credit and collections costs, and a portion of call center costs (Only in Matters, 2/16/10).

The POR financial risk adder for each utility, regardless of commodity, would be set at 20% of the applicable uncollectible percentage. The financial risk adder would be reset annually by multiplying the annual uncollectible percentage by 20%.

The commodity-related credit and collections and call center cost component is to be based on the allocated credit and collections and allocated call center costs in the final embedded cost study adopted in the rate case. The credit and collections and call center costs would be the same for the POR discount and the Merchant Function Charge.

Any over/under collections related to the credit and collections and call center costs component charged through the POR discount percentage would be added to any over/under collections related to the credit and collections and call center costs component charged through the MFC and reconciled through both the POR discount and MFC in the subsequent rate year.

To provide for a transition in the POR rate at RG&E, the allocated credit, collections, and call center costs would be phased into the POR discount rate over a two-year period. Under the phase-in, customers of ESCOs participating in the POR program offered by RG&E would pay the allocated amount of credit, collections, and call center administrative costs described above through a combination of a) an adjustment to the POR discount rate; and b) a separate temporary charge, called the POR Administration Charge, billed as a separate line item on the delivery portion of the bill. The adjustment to the POR discount rate during the first year of the two-year phase-in would recover 50% of the applicable costs while the POR Administration Charge would recover the remaining 50% of these costs. In the second year, the POR discount rate would recover the full amount of these costs and the POR Administration Charge would expire.

Under the stipulation, the MFCs would include the following rate components:

a) Commodity-related Uncollectible Costs (electric and gas);

b) Commodity-related Credit and Collections and Call Center costs;

c) Commodity-related Administrative costs;

d) Cash Working Capital on Purchased Power costs, if the New York ISO moves to weekly billing (electric only) and Cash Working Capital on Commodity Hedge Margin costs; and

e) Cash Working Capital on Storage Inventory Carrying Costs (gas only).

The commodity-related uncollectibles component would be developed for each for the following MFC groups: residential gas; non-residential gas; NYSEG electric - small (SC Nos. 1, 8, 12, 5, 6, 9 and streetlighting); NYSEG electric - large (SC Nos. 2, 3, 7); RG&E electric - small (SC Nos. 1, 2, 4 6 and streetlighting); RG&E electric - large (SC Nos. 3, 7, 8 and 9).

Gas Supply Matters

The joint proposal also included a stipulation entered into among the utilities and several retail gas supply parties.

Among other things, this gas supply stipulation provides that as of the beginning of the new rate year, the utilities would change the due date for a daily-metered customer's request to change gas supply from one provider to another from five business days prior to the end of the month to the fifteenth calendar day of the month. The switch day will remain on the first calendar day of the next month.

NYSEG is to consolidate Gas Supply Area 1 (GSA 1) and GSA 3, and would establish a Gas Reliability Surcharge for the consolidated GSA at the beginning of the rate year.

The utilities would also establish a collaborative to address any impacts of the GSA consolidation on mandatory capacity release assignment program pricing and the derivation of the gas reliability surcharge, and examine the costs and ramifications of and methodology for releasing capacity to ESCOs at the system weighted average cost of capacity, among other issues.

Starting April 1, 2011, ESCOs serving RG&E delivery customers would be required to provide capacity to meet 100% of their non-daily metered customers' load based on an average peak day of 66 Heating Degree Days (HDD) of load, instead of the previously-applicable design day requirement based on 75 HDD. On days exceeding 66 HDD, RG&E would supply the difference between 66 HDD and the HDD of the particular day. RG&E would implement a Gas Reliability Surcharge to recover the costs associated with retaining pipeline capacity to meet demand on behalf of ESCO non-daily metered customers at times between 66 and 75 HDD. The surcharge would apply to customers taking service from ESCOs under gas SCs 5, 7a and 9. RG&E would include the surcharge in the Small Transportation Service Rate Adjustment Statement. Surcharge revenues would be credited to the Gas Supply Charge.

RG&E's Gas Reliability Surcharge would be reduced by a proportionate share of revenues associated with the applicable share of non-migration capacity release, net off-system sales revenue, and pipeline supplier refunds related to services used in the derivation of the surcharge.

Beginning in 2011, on or before September 30 of each year, RG&E would provide a report to Staff and ESCOs that includes the calculation for the projected year's capacity requirements, a statement of the changes from the previous year's capacity requirements, a statement of the changes from the previous year, an explanation of the reason(s) or basis for the changes, and all associated workpapers.

Sempra Energy Solutions Seeks Use of CC&N Docket to Answer Arizona Retail Access Question

Sempra Energy Solutions (SES) has recommended to the Arizona Corporation Commission that the Commission use Sempra Energy Solutions' pending CC&N Application for a retail supply license (Docket E-03964A-06-0168) as a procedural vehicle within a tangible context for considering and resolving the underlying question of whether to resume retail electric competition at this time.

Sempra Energy Solutions requested that this suggestion be included in Staff's forthcoming report on its review of retail access under docket E-00000A-02-0051.

Sempra Energy Solutions said that its CC&N Application has been structured so as to not be dependent upon the legal status of the Commission's Retail Electric Competition Rules, as set forth at A.A.C. R14-2-1601 et seq. "In that regard, SES has suggested that the pertinent substantive features of those rules could be incorporated as compliance conditions in a Commission decision granting SES a CC&N to provide competitive retail electric service, with the CC&N itself being issued pursuant to the Commission's authority under A.R.S. § 40-281. Further, both SES' CC&N Application and the prepared testimony and exhibits filed by SES to date in Docket No. E-03964A-06-0168 have been designed to provide the Commission with that information necessary to enable it to fully discharge its constitutional obligations as to 'fair value' and 'just and reasonable' rate determinations, as discussed in the Phelps Dodge case," Sempra Energy Solutions added.

Because of the passage of time since the CC&N application was originally filed, Sempra Energy Solutions believes that it would be appropriate for the Commission to issue a further Procedural Order in Docket No. E-03964A-06-0168 providing for (i) an additional publication of public notice of SES' CC&N Application, (ii) a new deadline for the filing of requests for intervention, (iii) a series of dates for the filing of such additional testimony and exhibits by SES, the Commission's Staff and intervenors as those parties might desire, and (iv) such further procedural event dates as may be appropriate preliminary to an evidentiary hearing on the merits of SES' CC&N Application. "In so doing, the Commission would provide a procedural means within a tangible context for considering and resolving the underlying question of whether to resume retail electric competition at this time," Sempra Energy Solutions said.

According to Sempra Energy Solutions, Staff's report on retail access is due to be filed no later than 30 days following the effective date of the Commission's decision in Docket No. E-2069A-09-0346. It is unclear whether this docket number was a scrivener's error (the docket does not appear to exist), and Sempra Energy Solutions meant Docket No. E-20690A-09-0346, regarding whether SolarCity is considered a public service corporation when installing distributed solar generation hosted by governmental entities, schools and non-profits under Solar Service Agreements (SSAs). Under the Solar Service Agreements, SolarCity or other third-party investors (such as a bank) own the solar installations. This arrangement is required to take advantage of tax credits not available to entities not subject to taxes such as government entities. The customer owns the solar power under the Solar Service Agreement, but pays a fee for design, installation and maintenance of the solar facility based on the amount of electricity produced.

On July 12, the ACC issued an order finding SolarCity is not a public service corporation when it provides electric service to such government and non-profit entities from distributed solar installations owned by SolarCity or other third-party investors.

DPUC Formally Re-Opens UI Variable Peak Pricing Docket

The Connecticut DPUC has issued a final decision re-opening Docket 05-06-04 for the purpose of reviewing United Illuminating's variable peak pricing (VPP) tariff, how VPP rates are established, and UI's proposal to implement the VPP rate for all customers. In addition, the Department will conduct an evaluation of the mandatory Time-of-Day policy, and its prior direction to expand Time-of-Day rates to lower volume customers after the completion of implementation of mandatory Time-of-Day rates for high usage customers. The DPUC will also generally examine UI's seasonal rates (05-06-04RE06).

Currently, VPP is only available to customers taking service under Supplier of Last Resort Service (LRS). A 2008 order requires UI to expand VPP to all customers, including those taking service under Standard Service (SS) rates, effective July 1, 2010.

UI has proposed, for customers on Rates RT, GST, and LPT taking either Standard Service or Last Resort Service, to implement both on-peak and off-peak daily variable pricing based on the ISO New England Day-ahead Locational Marginal Prices for the Connecticut load zone. A constant amount (Adder) would be added to the arithmetic average of the day-ahead LMP's to determine the daily price for generation service. A separate Adder would be calculated for the on-peak period and off-peak period, for Standard Service and Last Resort Service, for each eligible rate schedule, respectively.

The Adders would be determined quarterly at the same time that Last Resort Service rates are determined for the next three month rate effective period. Each Adder would be equal to the difference between the respective Standard Service or Last Resort Service rate during the Last Resort Service rate effective period and an estimate of what the average LMP will be during that rate effective period.

The DPUC noted that UI proposed offering

VPP during the on-peak and off-peak periods, thereby implementing 24-hour VPP rates. "While 24-hour VPP rates may be desirable, this rate design deviates from the on-peak only VPP tariff currently in effect for UI's LRS customers," which the Department found to be inconsistent with its 2008 Rate Design order.

Additionally, the 2008 Rate Design decision states that UI will adjust the ISO-NE Day-ahead LMP to reflect the cost of capacity and other ancillary services not included in that price using an adjustment mechanism similar to that used by Connecticut Light and Power in CL&P's VPP rate. UI's proposed Adder does not appear to reflect CL&P's adjustment mechanism, the DPUC said.

Gateway Energy Services Conducting Time of Use Pilot at Oncor

Gateway Energy Services Corporation has launched a pilot Time-of-Use pricing program at Oncor, known as the Lifestyle Energy Plan, which will test two distinct Time-of-Use rate structures.

Participating customers will be held harmless under the pilots, and their monthly bills during the pilot will be based on their current flat rate structure, with shadow bills used for the TOU rates. Customers will have online access to reports that will show them details about their usage, as well as a side-by-side billing analysis of the Time-of-Use versus their current rate plan. Those customers who would have saved money under the Time-of-Use rates versus the flat rate will receive a bill credit equal to any savings at the end of the pilot. There will be no penalty to customers who would have paid higher costs had they been billed on the Time-of-Use rates. Customers completing a survey will also receive a $50 Visa Prepaid Card.

Gateway solicited, by letter, 287 of its customers in the Oncor service area for participation in the three-month pilots. Criteria for participation included residential customers who already have an Oncor-installed smart meter and are enrolled on Gateway's variable-rate plan, instead of a fixed rate. Of these customers, 51 customers opted in to the program by taking a brief survey and answering a series of demographic questions. Customers also evaluated eight common household power guzzlers by rating them as easy or hard to shift to hours outside of 2-6 p.m., which determined which pilot program the customers would receive.

Of the respondents, 18% qualified for the Busy Life Plan, which will give them a 20% discount on electricity usage on weekdays from 6 p.m. to 9 a.m. and all day on weekends. The plan includes a premium of 50% for power used between 9 a.m. and 6 p.m. The balance of customers (82%) qualified for the Max Savings Plan, giving them a 20% discount every day on usage during all hours outside of 2-6 p.m. with a 60% premium during those peak hours.

NiMo ... from 1

Staff selected the 250 kW threshold given that NiMo previously recommended 250 kW as the next step in transitioning more customers to hourly pricing under a 2006 plan, which was not implemented. "[A]s customers gain experience in hourly pricing, I would like to see this threshold lowered further in the future," Staff's witness added.

Benefits from moving additional customers to mandatory hourly pricing include potential reductions to peak period prices, enhanced peak period reliability, wholesale market power mitigation, a reduction in dependence on natural gas fueled generation, and more equitable pricing of customer bills than provided by the existing, less exact, average energy rate, Staff said.

Staff recommended two changes in the recovery of capacity costs from mandatory hourly pricing customers, coincident with the lowering of the threshold.

First, generation capacity costs for such customers should be recovered through a kW demand charge based on each customer's individual demand during the system peak hour, Staff said, rather than a usage-based charge reflecting usage throughout the year. Staff said that the current usage-based charge based on hours throughout the year results in customers, who reduce their demands at the system peak hour, not necessarily seeing a reduction in capacity costs, depending on their usage in the other hours which are included in the capacity cost calculation.

Additionally, Staff recommended that, for recovering capacity costs from all customer classes, the load factor calculation should utilize the demand of the class during the hour in which the New York system peaks, rather than the demand of the class during the hour in which the class itself peaks.

Staff also recommended that NiMo be directed to offer a voluntary hourly pricing option for medium sized commercial and industrial customers not subject to mandatory hourly pricing, as NiMo is the only large investor-owned utility in New York that does not have a voluntary time-variant pricing option for such customers.

Merchant Function Charges

As only reported in *Matters*, NiMo has proposed eliminating its current backout credit mechanism for certain commodity-related expenses, instead recovering such costs through a bypassable Merchant Function Charge (MFC).

Staff agreed with NiMo's proposed level for the commodity-related credit and collections component of the MFCs, and supply procurement component of the MFCs (see amounts in our 2/1/10 story).

However, while Staff agreed with the general methodology used by NiMo to obtain the commodity-related uncollectible expense component of the MFC, Staff recommended using different values for certain inputs. Specifically, Staff said that using actual electric write-offs, with data updated as of May 31, 2010, reduces the historic test year uncollectible rate to 1.3232%, versus the 1.687% that resulted when NiMo applied a write-off allocation factor to the test year's electric revenue, rather than actual write-offs. While Staff's changes would affect the class-specific uncollectible rates used in the MFCs, Staff did not provide updated class-specific uncollectible numbers.

Staff agreed with NiMo's proposal to true-up MFC revenues related to the supply procurement, commodity-related credit and collections, and commodity-related working capital components. However, Staff opposed NiMo's proposal to true-up the forecast of the MFC uncollectible rate to the actual rate, since it would reduce the utility's incentive to manage uncollectibles. Staff recommended that the uncollectible rate approved by the Commission in the rate case be used until modified by the Commission in NiMo's next rate proceeding.

Staff agreed with NiMo's proposal to update the Purchase of Receivables discount rate to reflect the MFC commodity-related uncollectible percentage and the commodity-related credit and collections rates.

Commodity Rate Design & Procurement

As previously reported, NiMo petitioned to revise the design of its electric commodity rate effective January 1, 2012, which is the second year of its proposed three-year rate plan.

Among other things, NiMo would use a monthly forecast of New York ISO day-ahead prices in each Load Zone, rather than using an average of hourly prices in the NYISO market, in setting mass market rates. Additionally, NiMo would create a new Commodity Adjustment Mechanism containing the benefits/costs of new hedges applicable only to bundled service customers which would be reflected in the commodity portion of the bill. A Legacy Transition Charge applicable to the delivery portion of the bill would recover pre-2001 legacy hedges on a nonbypassable basis.

Staff agreed with NiMo's proposals in concept. However, for various reasons related to delivery service, Staff is proposing a one-year rate plan rather than a three-year rate plan, and thus NiMo's proposed commodity-rate changes would not be encompassed in the rate year. For this reason, Staff recommended that NiMo re-submit its commodity pricing proposal 45 days after new delivery rates are approved by the Commission in the instant case, and that a technical conference be held regarding the proposal.

Regarding procurement, as noted by *Matters*, NiMo would create, "a managed portfolio with a sufficiently diverse mix of contract types and contract lengths for mass market customers who procure power commodity from the Company to accomplish the goal of managing price volatility," though the portfolio would not extend to 100% of requirements to allow the continued pass-through of market costs for a portion of supply.

Constellation Energy Commodities Group

filed testimony opposing this procurement approach, calling it inconsistent with National Grid's own findings regarding the optimal method of procurement as filed in a Rhode Island PUC proceeding.

Constellation noted that National Grid, in the Rhode Island proceeding, submitted a 2010 Procurement Structure Analysis which concluded that a full requirements structure is the superior method of mass market supply procurement, as it greatly reduces risks and the need for utility implementation expenditures, at only a $0.72/MWh cost increase in comparison to a managed portfolio approach.

Constellation cited testimony from National Grid during a Rhode Island technical session as indicating that National Grid intends to use a full requirements approach in all of its service areas, since National Grid reported that its decision to utilize full requirements procurements, "was company-wide and ... was in the context of a long-term procurement strategy review, so this was the one conclusion that we came to from a company-wide basis."

According to Constellation, National Grid said during an April Rhode Island technical session that it had not yet "proposed [the full requirements structure] in Massachusetts and New York," but that Grid intended to do so, as its representatives stated that it, "will start [discussions in New York] now because we have to file a proposal."

While New York has set several benchmarks for the limitation of volatility to which mass market customers are exposed, Constellation said that a hedging strategy utilizing an open and competitive procurement of overlapping, medium-term full requirements service contracts could achieve such benchmarks.

Md. POR ... from 1

Furthermore, Nazarian expressed exasperation that the July 1 compliance filings -- at least the third set of compliance tariffs filed by the utilities since the RM 17 rulemaking order -- still apparently require significant modifications. "This always keeps happening," with POR, Nazarian chided, "every single time."

The utilities noted, however (especially with respect to BGE's tariff), that much of the language Staff is now seeking to change has been in place since the utilities' November 2009 compliance filings, with the now controversial provisions never raising concern from Staff or other interested parties. While Staff is free to seek tariff modifications, BGE noted that many changes sought by Staff did not, in BGE's view, relate to whether BGE had complied with the Commission's June POR order, and were issues better addressed outside of the compliance filing process. Hence, many of the issues were deferred to the working groups.

The bottom line is that none of the few changes ordered by the Commission yesterday, or those that were deferred to the working groups, will or would have altered the previously approved discount rates to be charged to suppliers starting today (or in the case of BGE's gas program, the discount rates filed July 1 which were approved yesterday). Many of the items drawing controversy related to the establishment of the future discount rates, and how specific the tariffs should be in describing their calculations, and whether language in the tariff should be more permissive with respect to certain components currently not being collected (i.e. the risk factor).

Aside from the correction of outright errors, the Commission ordered three basic changes to the POR tariffs which take effect today.

First, the Commission required the inclusion of language that clarifies that the risk factor, which will continue to be included in the tariff language despite being set at zero, may only be paid to the utility upon approval of the Commission. Commissioners had raised concerns that the current tariff language stating the risk factor "will" be paid, despite being set at zero, could have opened the door to the creation of a risk factor in future periods despite the lack of Commission approval.

Similarly, regarding the ability of the utilities to directly bill suppliers for unrecovered POR costs, should participation be insufficient to recover costs through the discount rate, the Commission held that any direct charge to suppliers may only be enacted upon approval from the Commission. Again, Commissioners were concerned that the filed tariff language granted the utilities the ability to directly charge suppliers for such costs without ever setting a tariffed charge for such recovery.

At BGE, the Commission also adjusted the tariff such that BGE will file proposed new POR discount rates for both gas and electric supplies by April 30 annually, for a July 1 effective date. However, the issue of when the POR discount rate should change (such as making the new rates coincident to the start of a new SOS pricing period on June 1) will likely be addressed in the working groups.

Staff had recommended that the Commission strike from the tariffs all language related to the discount rate except for the discount rates themselves. The Commission rejected this solution for the purpose of allowing POR to be implemented today, but Staff will likely raise the appropriate description, if any, of the discount rate calculation to be included in the tariffs in the working group sessions.

"The tariff language should only reflect costs that are included in the current discount rate. It is not necessary include language describing costs that may be included in future rates if approved by the Commission [such as the risk factor]," Staff said.

Additionally, Staff objected to BGE's filed language describing the POR reconciliation component since the filed tariff sets an interest rate for such reconciliation amounts equal to the company's rate of return from its most recent authorized base rate case. Staff does not believe that the appropriate level of interest had been addressed by the Commission, and recommended that the matter of the level of the reconciliation interest rate be addressed in BGE's next discount rate filing, and not pre-determined within the tariff language. The Commission, however, let the current language stand, though the issue will be taken up in the working groups.

Staff also suggested during the administrative meeting that, if the POR reconciliation balance becomes significantly large, it may be appropriate to adjust the POR rate prior to the annual adjustment to avoid a large reconciliation.