Energy Choice Matters
January 13, 2010

# First Choice Power, OPC Support Phase-Out of "Advanced" Pay Products with AMI Deployment

First Choice Power and the Office of Public Utility Counsel support requiring all prepaid service in ERCOT to eventually be conducted through use of a HAN or other in-home device, but several other REPs said that such a requirement would place a burden on REPs and potentially raise costs to customers. Parties were responding to PUCT Staff's strawman proposal governing prepaid service without the use of an in-home device (35533, Only in Matters, 12/11/09).

First Choice Power, "believes that all prepaid electric service products, however characterized or defined, should be governed by PUCT Subst. Rule 25.498 [relating to use of an in-home device]. The 'advanced pay' form of prepaid electricity that exists today, and that this rule purports to address, has created a significant negative consumer perception of prepaid electric service in general ... That perception will be difficult to overcome as REPs implement functional prepaid service that is compliant with PUCT Subst. Rule 25.498," First Choice said. The Office of Public Utility Counsel also supports phasing-out the use of advance pay products which do not use an in-home device once advanced meter deployment is ubiquitous.

However, the Alliance for Retail Markets, ePsolutions, Gexa Energy, Reliant Energy, the Texas Energy Association for Marketers, and TXU (the Retail Market Group), argued that customers should not be required to transition to a product with a HAN device or any other "pay as you go" program once an advanced meter is installed at their home. "Many REPs in this market have offered an advance payment or 'financial prepaid' model that has worked well in meeting the needs of consumers," the Retail Market Group said.

"To place the burden of supplying a separate device on the REP is both onerous and counterproductive as the cost of the unit would ultimately be borne by the consumer, and potentially stifling to the development of new products and services," the Retail Market Group added. Several other REPs, such as Young Energy, made similar comments.

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# Sempra Energy Solutions Revises Local RA Load Migration Proposal

Sempra Energy Solutions has refined its proposal to account for load migration in California local resource adequacy requirements to, among other things, delay implementing the compliance obligation associated with migrated load until a liquid standard capacity product market develops, and to aggregate several local Resource Adequacy areas (R.09-10-032, Only in Matters, 12/24/09).

The main design of Sempra Energy Solutions' model remains unchanged. LSEs would annually assign a Local Resource Adequacy (RA) capacity obligation to each and every demand metered end-use customer in their service portfolio. The obligation methodology would be based on the end-use customer's August peak demand (2010 for the 2011 compliance year) at the time of the CAISO's August system peak, by service account, divided by the LSE's total 2010 August peak demand for all of the LSE's customers at the local area's August system peak time in that local area. This number is the customer's Peak-to-Load Ratio, by local area aggregated by Utility Distribution

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## Clarification Note to Readers:

In yesterday's story concerning the Retail Energy Supply Association's new federal monitoring group, Energy Choice Matters, beginning in the 7th paragraph of the story, provided its own analysis and characterization of several FERC decisions and FERC's treatment of retail market issues. Although the intent was to plainly and clearly reflect Energy Choice Matters' own view, Energy Choice Matters further clarifies that any and all discussion of FERC's decisions and FERC's view of retail markets as characterized in the story were solely those of Energy Choice Matters, and in no way reflect the views or position of the Retail Energy Supply Association. Energy Choice Matters' analysis came solely from our experience in the industry, and at no time did Energy Choice Matters discuss with any RESA member or official any past or present FERC proceeding, or any other issue related to FERC's treatment or view of retail markets.

## P3 Urges Maryland PSC to End Questions of Market's Future

"[I]t is time to bring to a close the questions about Maryland's electricity future that have clouded the state's investment climate for several years," the PJM Power Providers Group (P3) said in a letter to the Maryland PSC responding to the latest proposals from Gov. Martin O'Malley to build rate regulated generation and procure long-term supply contracts (Cases 9117, 9214, Only in Matters, 12/21/10).

"[I]t is particularly difficult to commit capital to long-lived generation projects in Maryland given an enhanced level of regulatory uncertainty over re-monopolization," P3 added. "Rate-based generation is likely to cost more than existing market-based supply," P3 added, and would transfer the risk of construction cost overruns and delays, fuel price swings, environmental compliance costs, and plant outages to customers.

P3 noted that the Levitan Study, which the O'Malley administration says shows savings from new rate regulated generation, was conducted at a time of record high energy prices (with gas prices and forecasts in the $8-9/mmbtu range), and assumed higher capacity prices than were reflected in the most recent RPM auction. "Clearly there have been significant changes since this 2008 study was completed that the Commission should consider rather than rely upon this outdated research."

Maryland's penchant to consider re-regulation annually has, "left Maryland with the unfortunate distinction of being one of the least attractive states in the nation in which to consider an investment in the electricity sector ... Conversely, competitive markets in other states have attracted significant investments and several projects that benefit Maryland have been built in other states," P3 said.

P3 noted several measures implemented by the Pennsylvania PUC in the past year to foster retail competition, such as establishing POR, making customer lists available, developing education programs, and refining EDI processes. "Consumers would be well-served if this Commission similarly took affirmative steps to encourage retail competition," P3 said.

## NYISO Files Recommendations on Lake Erie Loop Flows

The New York ISO, in conjunction with PJM, the Midwest ISO and Ontario IESO have recommended a series of market solutions to address Lake Erie loop flows including: (a) Buy-Through of Congestion, (b) Congestion Management/Market-to-Market Coordination, (c) Interface Pricing Revisions, and (d) Interregional Transaction Coordination. NYISO's recommendations were filed with FERC in docket ER08-1281.

The proposed Buy-Through of Congestion solution is designed to address loop flows by allocating a more complete and accurate measure of the costs caused by external transactions (such as imports, exports, and wheels-through) to the cost-causing transactions, NYISO said. The current practice for scheduling interregional transactions only requires scheduling parties to pay for the congestion charges assessed by the Balancing Authorities that are part of the "contract path" over which an external transaction is scheduled. Costs that an external transaction imposes on Balancing Authorities that are not included in the contract path are not currently considered in the scheduling process, nor are they charged to the scheduling entity. "Buy-Through of Congestion addresses this shortcoming by more completely assessing the congestion charges associated with scheduling an interregional transaction to the scheduling entity," NYISO said.

The proposed Buy-Through of Congestion Broader Regional Market solution will assign off-contract path power flows comparable congestion cost exposure for equivalent use of the transmission network to contract path power flows. The Buy-Through of Congestion bidding features will allow the scheduling party to indicate if it is, or is not, willing to pay the congestion charges caused by its transactions' off-contract path flow impacts. If a transaction party indicates it is not willing to pay congestion charges, its transaction will be removed if the off-contract path flows created by the transaction add to congestion costs in a participating off-contract path ISO or RTO. Once removed, the transaction will not be reinstated until the neighboring ISO/RTO indicates that the congestion on the impacted flowgate has been adequately relieved, NYISO said.

NYISO reported that a prerequisite to implementing the Buy-Through Congestion and Congestion Management/Market-to-Market Coordination solutions is the completion of NERC's Parallel Flow Visualization tool (or the development of an alternative thereto), which will significantly improve the ability to accurately perform generation-to-load calculations and will make available common and consistent information regarding the sources of power flows and their impacts.

NYISO said that the re-dispatch of generators within a Balancing Authority that is interconnected with the Balancing Authority that is experiencing the congestion may be able to address transmission constraints more cost effectively than the re-dispatch of generators or other control action taken by the congested Balancing Authority. A Congestion Management, or Market-to-Market Coordination, protocol (1) allows for inter-Balancing Authority dispatch to manage congestion if, and to the extent, an interconnected Balancing Authority can re-dispatch resources to alleviate the congestion at a lower cost than the Balancing Authority that is experiencing the congestion, and (2) permits the appropriate settlement (payment) based on the facts and circumstances of each situation.

In order to effectively implement Market-to-Market Coordination it is necessary to (a) pre-identify a consistent set of constraints that multiple Balancing Authorities can address through re-dispatch actions, (b) develop an agreed to baseline of allowable usage of each others transmission networks, and (c) establish data sharing protocols to communicate real-time constraint management costs between Balancing Authorities. After-the-fact calculation of settlement charges will be performed to provide compensation for the dispatch action when the system flows are less than pre-defined baseline values. Overuse of a neighboring Balancing Authority's transmission system that results in costs to the neighboring Balancing Authority must be redressed. Market-to-Market Coordination will be incorporated directly into a regions dispatch and price setting protocols to maintain the existing consistency between resource schedules and prices. No other explicit charge or refund to a redispatched resource will be necessary, NYISO said.

## PUCT Says More Support Needed to Uphold Tres Amigas Disclaimer of FERC Jurisdiction

The PUCT told FERC that it is, "concerned that the [federal] Commission may need more legal and factual information to issue the declaration of disclaimer requested by Tres Amigas," and preserve the PUCT's sole jurisdiction over ERCOT (EL10-22).

Though Tres Amigas, in connection with its project to link ERCOT, the Eastern Interconnect, and Western Interconnect, made three cases for the disclaimer of FERC jurisdiction, several stakeholders, such as CenterPoint Energy, have noted the weak support for each rationale, while others, such as Occidental Power Marketing, argued that Tres Amigas has failed to justify a waiver. Occidental contended that the, "facts set forth by Tres Amigas conclusively demonstrate that electric energy from ERCOT will be transmitted from Texas to the interstate grids that serve other states where the electric energy will be consumed on a continuous and 'massive' basis ... and that electric energy from the interstate grids will be sold and consumed in ERCOT."

The PUCT said that relying upon Sections 210-212 of the Federal Power Act may be the most promising argument supporting a waiver of FERC jurisdiction, but noted that use of Sections 210-212 is complicated due to the unbundling of transmission/distribution and retail service in ERCOT. Due to the unbundling, "[c]ompanies that operate as transmission-and-distribution utilities in ERCOT appear not to be electric utilities under the FPA, and for this reason Sections 210 and 211 may not afford a basis for a Commission order to interconnect ERCOT to the Tres Amigas facility in a way that would preserve the PUCT's jurisdiction of ERCOT transmission," the PUCT said. Still, the Texas Commission cited *Kiowa Power Partners, LLC (2002)* as suggesting that, "entities exist or may be created in ERCOT that would allow use of Sections 210-212 under certain factual situations to build interconnections with the Tres Amigas facilities that will not remove the PUCT's jurisdiction over wholesale transmission and sales within ERCOT."

## *Briefly:*

**BGE Home Begins Marketing Electricity at BGE**

BGE Home, branded as Constellation Electric, has launched residential electric offers in the Baltimore Gas & Electric territory. BGE Home is offering a 12-month fixed rate at 10.35¢/kWh, and a 24-month fixed rate at 10.25¢/kWh, versus the annualized BGE price to compare of 11.97¢/kWh, and the actual SOS generation plus transmission rate of 11.527¢/kWh. Both products include a $150 termination fee.

**Palmco Energy Seeks Md. Electric, Gas Licenses**

Palmco Energy has filed for both electric and natural gas supply licenses at the Maryland PSC. For gas, Palmco will serve all customer classes at all LDCs. For electricity, Palmco will serve residential and commercial customers at the four investor-owned utilities. Palmco is currently licensed in New Jersey and Pennsylvania (both commodities), and has a pending application for a Connecticut electric license.

**PJM Schedules ATSI Integration Auctions**

Consistent with the American Transmission Systems Inc. integration plan, PJM said that will hold two simultaneous integration capacity auctions in March 2010 to secure electric capacity for delivery years 2011-2012 and 2012-2013 to meet the capacity supply obligations of FirstEnergy's operating utilities within the footprint of ATSI. Two separate auctions will be held simultaneously (one for each delivery year) using a process similar to PJM's incremental RPM auctions. The auctions will open March 15 and close March 19. The ATSI operating utilities seek about 13,500 MW of resource-specific unforced capacity for 2011-2012 and 13,900 MW for 2012-2013. PJM will conduct a Fixed Resource Requirement Integration Auction informational stakeholder session on January 19.

## *Prepay ... from 1*

dPi Energy noted that prepay customers tend to switch REPs every two to three months, which raises cost and logistical concerns regarding a model requiring the use of a HAN or in-home device. Given the frequent turnover of prepaid accounts, "it is extremely likely that the prepaid REP would find itself provisioning a particular apartment unit [with a HAN device] over and over again, as the prior residents took the HAN with them when they moved. This would be a significant cost barrier," dPi said. dPi further noted that many prepay customers require expedited Move-Ins, precluding the ability to install a HAN device coincident to the customer's start of electric service.

dPi Energy strongly opposed any requirement to use an in-home device as, "impractical and overly costly, to the point that were such a plan to be implemented, it would result in the end of advance-pay REPs, with their customers being driven to the POLR."

The strawman's provisions allowing REPs to collect up to a $5 payment processing fee and a flat $50 deposit for prepay products drew criticism from consumer groups. Texas

Ratepayers Organization to Save Energy and Texas Legal Services Center noted that such a payment processing fee will penalize customers who prepay their accounts more frequently because they can only make small payments, raising their cost of service versus a prepaid customer refilling their prepay balance only once per month. ROSE and TLSC also opposed deposit requirements as inconsistent with the purported benefits of prepay service.

The Retail Market Group opposed the $5 limit on processing fees, calling the cap arbitrary and stating that competition will determine the appropriate amount of any service fee. Moreover, a REP cannot control the fee charged by third-party agents receiving payment, and capping the fee would require REPs to forego use of agents charging fees in excess of the cap, limiting customers' payment options, the Retail Market Group added.

The Retail Market Group also opposed the flat $50 deposit requirement as inconsistent with how deposit limits are typically calculated elsewhere in the Substantive Rules, which take into account variations in each customer's usage. The Retail Market Group stressed that security deposits are still a necessary protection under the advance pay model (not using an in-home device) for at least two reasons. First, there is still exposure between the time that a customer's advance payment runs out and disconnection. Second, there is exposure if the estimated consumption built into setting the deposit and/or the estimated consumption built into setting the required advance payment underestimates the customer's actual usage.

Rather than a flat deposit cap, the Retail Market Group recommended limiting deposits to 25% of the two highest months' estimated consumption.

Consumer groups faulted the strawman's language regarding the provision of updated account balance information to customers as not providing timely information, while REPs called such status updates impractical for customers not on an in-home device.

"An important aspect of prepaid service is the responsibility of the REP to communicate the status of the customer's account to the consumer," TLSC and ROSE said, who noted that, for rules governing prepaid service with an in-home device, this information must be provided continuously or within two hours of a customer's request. Under the strawman for advance pay, REPs are given until 5 p.m. the next day to communicate such information. If not requested, REPs must provide the customer with an updated balance every two weeks.

"A customer should not need to request information, such as the customer's current estimated balance and number of days of paid electric service remaining, from its provider; rather, the communication should automatically be sent to the customer by the provider. Also, when a customer requests their current estimated balance from their REP, the customer should receive that information from their REP as soon as practicable, rather than waiting until 5 p.m. the following day," OPC added.

The Retail Market Group said that REPs can not meaningfully provide the customer with an updated balance at least every two weeks if such REPs are using legacy meters for their advance pay products, since consumption information is only updated with the monthly TDU meter read. The REPs recommended striking the requirement from the rule.

OPC cited that same monthly billing cycle logistic in recommending that REPs be prohibited from requiring prepayment more frequently than monthly. "Unless the REP has actual meter read data, to true-up with a prior estimate, the customer should not receive another bill until the next month when the provider receives new meter read data. The REP should be permitted to send statements but not to require payment more frequently than monthly when the REP has meter read data on which to base the charges," OPC said.

OPC also opposed the shortened disconnect timeline afforded to prepaid REPs not using an in-home device, and recommended replacing the timelines with the standard 10-day notice requirement. ROSE and TLSC continue to object to any prepaid product that does not ensure that, once the customer has paid, service is guaranteed for the duration of the billing cycle.

Young Energy objected to the strawman's provision tying the shortest disconnection period (five days) to the requirement that the REP must be able to accept payments on a 24-hour basis.

Young argued that accepting payments from 6 a.m. through 10 p.m. is sufficient.

First Choice Power argued that the strawman should not allow REPs to disconnect a customer based on estimated usage developed by the REP, rather than the TDU.

The Retail Market Group objected to the proposed Electricity Facts Label for prepaid products in the strawman, which would require REPs to list the estimated amount of days that a certain prepayment amount (e.g. $20, $50, etc.) is expected to last. Such a projection of days of prepaid service per dollar amount will create false customer expectations, REPs said, since it is inappropriate to assume that the number of kWh consumed each day will be approximately equal across all days of the month. Daily usage can vary in a number of ways, REPs noted, based on customers' schedules (whether they are at work, school, etc.), and weather.

The Retail Market Group further opposed a requirement compelling advance pay REPs to offer levelized billing, since under average billing, the customer at times will pay less than is being consumed, nullifying the rationale of prepaid service.

ROSE and TLSC requested that the Commission conduct a formal inquiry of prepaid service by requiring all REPs and regulated utilities to provide the number of customers on their system taking prepaid service, the price charged, any surcharges imposed, the applicable terms of service or tariff, and other relevant information.

Both OPC and the Retail Market Group suggested clarifying that prepaid service not using a prepaid device should be defined as "advanced payment," which the Retail Market Group would define as a payment option under which a customer is billed, and is obligated pay, for electricity in advance of consumption based on estimated future consumption. OPC proposed a similar definition.

The Retail Market Group further argued that the advance payment option should be available for any product, and should not be tied to a specific rate plan.

## Local RA ... *from 1*

Company (UDC), and would be a number less than 1.000. The sum of all of an LSE's customer's Peak-to-Load Ratios should add to approximately 1.000 for each local utility service area.

Each customer's Peak-to-Load Ratio would then be multiplied by the LSE's California Energy Commission-assigned Local Resource Adequacy capacity obligation for 2011 (assuming a 2011 compliance year) for that customer's local utility service area.

The result of this exercise would be the end-use customer's Local Area Requirement (LAR) Obligation based on the CEC-assigned Local Resource Adequacy capacity obligation for the compliance year.

Per Sempra Energy Solutions' proposal, as end-use customers migrate during the year from one LSE to another, the losing LSE would identify the account(s) and the associated LAR Obligation to the CEC and the Energy Division of the PUC. The migrating customer(s) would also be identified on the gaining LSE's compliance showings. The Energy Division would match this migration and confirm the release of the Local Resource Adequacy capacity obligation from the losing LSE and impose an additional Local Resource Adequacy capacity obligation on the gaining LSE. At the same time, the gaining LSE would identify the additional Local Resource Adequacy capacity used to meet the incoming load.

For simplification purposes and materiality concerns, only accounts that are demand metered would be eligible for LAR Obligation migration. Sempra Energy Solutions said that this limit addresses two concerns: (1) what methodology should be used to calculate a service account's LAR Obligation if they do not have recorded historical demand readings; and (2) the ability to apply a materiality threshold to the transfer based on recorded load.

Among the revisions to its proposal is that Sempra Energy Solutions now recommends that implementation of a local true-up mechanism be delayed until at least the third quarter of 2011 to allow time for the market to develop a tradable, liquid standard capacity product, in recognition of concerns that local Resource Adequacy capacity may not be available in relatively small amounts and for short-term (less than 12-month) periods absent a liquid market.

To further address local area Resource Adequacy capacity liquidity concerns, local Resource Adequacy areas would be aggregated into two local Resource Adequacy capacity true-up obligations areas: NP-26 and SP-26, Sempra Energy Solutions said. LSEs would still be obligated to procure from Resource Adequacy units within the local area, but an LSE gaining load in the SDG&E Local Capacity Area (LCA) would be able to meet its additional LAR Obligation by procuring Resource Adequacy capacity from Resource Adequacy units in the San Diego, L.A. Basin or Big Creek/Ventura LCAs. This will allow LSEs more flexibility and options in buying and selling local Resource Adequacy capacity, while ensuring that Local Resource Adequacy requirements continue to be met.

Sempra Energy Solutions further refined its proposal so that only load migration of 5 MW or more within either the NP-26 or SP-26 area would trigger an LSE's migration compliance obligation, with the migration compliance obligation waived for the quarter if the aggregate migration for an LSE is less than 5 MW.

To address the concerns of asymmetry, Sempra Energy Solutions said that the $40.00 per kW-year trigger price for Local RA capacity would remain in effect, and the three utilities, which "undeniably" control the vast majority of Local Resource Adequacy capacity, should endeavor to make any excess Local Resource Adequacy capacity available for purchase. The utilities could sell their excess Local Resource Adequacy via a quarterly RFO process or similar non-discriminatory process, as the sale of Local Resource Adequacy capacity reduces the costs of utility procurement for the utilities' bundled customers, Sempra Energy Solutions added.

Sempra Energy Solutions' updated proposal also requires only quarterly migration filings, rather than monthly as originally proposed.

The Utility Reform Network supported Sempra Energy Solutions' general approach, but recommended a change in the Peak-to-Load Ratios, arguing that Sempra Energy Solutions' proposal is too complicated since the ratio would be different for each customer served by the LSE, and would change once the customer migrates to a new LSE which will likely have a different aggregate peak demand.

TURN instead proposed use of a Local-to-Peak Ratio (LPR), which would be the same for every customer and every LSE in a given IOU territory. The LPR would be determined by the ratio of the total Local Resource Adequacy obligation for the service territory in MW (as adopted by the PUC in its June decision) divided by the total CEC forecasted or actual recorded coincident peak load for the same service territory. TURN's proposal also explicitly contemplates use of the "current customer" approach to forecasting the loads of each LSE rather than the currently-adopted "best estimates" approach, while TURN said that the Sempra Energy Solutions proposal is silent on that question.

TURN also proposed allowing unbundling of the "local attribute" of resources that qualify to provide Local Resource Adequacy. TURN believes that such unbundling is feasible, and would be useful if the Local Resource Adequacy load migration proposal is adopted. TURN stressed that unbundling would only occur among LSEs, and that generators would not have a separate System Resource Adequacy obligation to one LSE, and a Local Resource Adequacy obligation to another, because the obligation is to the CAISO and not to any particular LSE. "Thus, a generator could not sell System RA to one LSE and Local RA to another. However, once a unit has sold its RA capacity and subjected itself to the RA must-offer obligation to the CAISO, there is no reason why the purchasing LSE could not sell off excess Local RA credits to another LSE that needs them," TURN said.

"Indeed, TURN reasonably suspects that allowing such transactions would result in a much more liquid market for Local RA, especially in the context of periodic true-ups for load migration. Today an LSE may be 'long Local' but nonetheless reluctant to sell off that excess capacity, because it may at the same time be 'short' or in balance for its System RA obligations," TURN added.