Energy Choice Matters

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CPV Maryland Petitions for Long-Term Utility Contract for St. Charles Plant

CPV Maryland asked the Maryland PSC to order the state's utilities to enter into a long-term contract for energy and capacity from its St. Charles combined cycle project, seeking a 14.6% return on equity under the 20-year contract. CPV claimed that ratepayer-backed, long-term contracts are needed for the project to move forward, and that it cannot be financed without such an offtake agreement.

CPV made its request in Case 9117, the PSC's long-standing and still pending review of SOS procurement policies. In that case, as well as the PSC's investigation into reliability shortfalls (9149), CPV has aggressively sought to change Commission policy to require long-term contracting between SOS providers and generators (Matters, 10/21/08).

Despite advocating for a Commission-ordered PPA that would not even be subject to a competitive RFP, Doug Egan, chairman of CPV Maryland's parent Competitive Power Ventures, insisted that, "We are strong believers in the power of markets to drive wholesale-level savings that translate into real dollars in ratepayer's pockets."

CPV Maryland is seeking a 20-year PPA with one or more of the state's electric utilities for all of the capacity and energy from CPV Maryland's 640-MW, combined-cycle natural gas-fired generating station which CPV proposes to build in Charles County, Maryland. CPV Maryland requested that should the utilities fail to execute a long-term contract within thirty days of a Commission order, the PSC itself will negotiate one or more such contracts on the utilities' behalf.

CPV Maryland would receive a 14.6% return on equity under its proposal.

CPV Maryland claimed that its project, "unquestionably would reduce rates and rate volatility while providing additional, and considerable, economic and environmental benefits to the State."

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RESA Asks N.Y. PSC to Impose Five-Year Stay-Out on NYSEG/RG&E Fixed Price Option

The New York PSC should prohibit NYSEG and Rochester Gas & Electric from offering a fixed price option (FPO) for five years as part of accepting the utilities' notice to discontinue the product at the end of 2009 and institute a revised form of market pricing, the Retail Energy Supply Association said in comments (09-E-0228 et. al., Matters, 7/3/09).

While RESA applauded the termination of the fixed price option for 2010, the retail group questioned if the product would return when market conditions improve.

"In this regard, it is logical to conclude that the Companies' sudden conversion to a market based supply service may be a function of the recent collapse in commodity prices which has created significant financial risks for entities like the Companies' that offered fixed-price products. As the Commission may remember, a similar fate befell NYSEG when it had previously offered a natural gas fixed-price rate ... It does appear that the Companies' willingness to offer [an] FPO product is based upon its assessment of the potential movement in commodity markets and if in the near future its view changes, it may then seek to implement an FPO once again," RESA said.

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Gateway Energy Services Expanding to Columbia Ohio

Gateway Energy Services Corporation is entering the Columbia Gas of Ohio retail market, following its return to the Dominion East Ohio market earlier this year.

Gateway said it selected Columbia over Vectren Energy Delivery, which uses a Standard Service Offer auction to set retail prices, due metropolitan areas such as Toledo and Columbus in Columbia's territory. Columbia still uses a Gas Cost Recovery rate for retail pricing, but has applied to institute a Standard Service Offer auction.

"Ohio is a mature market and its residents are well-educated in the concept of choice," Gateway CEO Steven Maslak said. "We chose Ohio for expansion because our buying practices and business model fit well with the state's vision of deregulation," Maslak added.

Gateway will offer a variable-rate plan and 12- and 24-month fixed rate plans to residential and small commercial customers at Columbia.

With its current Dominion East Ohio products, Gateway is offering a $50 Visa prepaid card with enrollment.

UGI Penn Settlement Modifies Imbalance Trading Fee, Sets Class Specific MFCs

UGI Penn Natural Gas has withdrawn several tariff provisions opposed by retail suppliers as part of a settlement in its Pennsylvania natural gas rate case. UGI Penn would also implement a Merchant Function Charge to implement unbundled uncollectible costs under the stipulation, which is supported by the LDC, the PUC Office of Trial Staff, Office of Consumer Advocate, Office of Small Business Advocate, Retail Energy Supply Association, and other parties.

In its rate proposal, UGI Penn had applied to calculate its critical Maximum Daily Excess Balancing Charges based upon the gas index prices for Transco Zone 6 or Texas Eastern Zone M-3. RESA opposed the use of Texas Eastern Zone M-3 because gas cannot be delivered directly from that point to UGI Penn's system. The settlement eliminates the use of Texas Eastern Zone M-3.

The stipulation also modifies UGI Penn's supply transfer (imbalance trading) charge from 25¢/Mcf to $125 per transaction. RESA had said that the supply transfer fee was too high and should not be based on volume. The settlement also clarifies that supply transfers will be allowed where such transfer is physically possible given pipeline interconnections and delivery point limitations.

Under the settlement, UGI Penn will only recall capacity on critical days where the supplier fails to nominate such capacity in a timely manner. UGI Penn will also clarify that it will not restrict marketer deliveries for economic reasons.

For Rate MBS (Monthly Balancing Service), UGI Penn will eliminate Balance Account Valuations, as RESA said that the Balance Account Valuation feature would significantly reduce the value of Rate MBS service.

The current daily balancing tolerance of 2.5% and current collateral requirements at UGI Penn will be addressed in the PUC's generic rulemaking on such natural gas market issues, rather than in the rate case.

UGI Penn does not believe that most Supplier of Last Resort costs should be unbundled, since it must stand ready to serve all customers. However, in its rate application it did apply to unbundle from base rates uncollectible expenses associated with purchased gas costs. UGI Penn applied to move such costs into a new Merchant Function Charge.

Originally, UGI Penn proposed an equal Merchant Function Charge for all classes. Under the settlement, it will apply a class specific uncollectible rate in the Merchant Function Charge of 3.20% to Rate R customers, and a rate of 0.4% for Rate N customers. Merchant Function Charges will be reflected in the price to compare.

Calif. Generators Seek Expedited Technical Conference on Exceptional Dispatch

NRG Power Marketing and other California generators petitioned FERC for an expedited technical conference to address the use of the Exceptional Dispatch mechanism by the

California ISO, which has been used some 1,000 times in just six weeks. The Western Power Trading Forum contemporaneously filed a motion for a technical conference (ER08-1178).

In June, generators protested the frequency of Exceptional Dispatch use by the CAISO as well as the lack of specific data concerning such dispatch in reports filed with FERC (Matters, 6/9/09).

The CAISO's latest exceptional dispatch report shows that CAISO ordered over 1,000 Exceptional Dispatch commitments in the six weeks since the beginning of the Market Redesign and Technology Upgrade market. That amounts to one Exceptional Dispatch commitment per hour of market operation, NRG said.

"Particularly troubling is the CAISO's continued issuance of Exceptional Dispatch commitments in the Day-Ahead time frame, prior to allowing the market to return uncorrupted results," NRG added.

"Immediate Commission action is necessary because the CAISO's routine use of what is designed to be an 'exceptional' market intervention mechanism is distorting market clearing prices in California. This is because, at least in the Day-Ahead timeframe, the CAISO appears to be Exceptionally Dispatching high heat rate units (i.e., more expensive units) prior to allowing market mechanisms to resolve constraints without intervention," NRG said.

At the technical conference, NRG urged FERC to investigate whether the volume of out-of-market procurement engaged in by the CAISO is artificially suppressing market clearing prices on an hourly basis. "The undeniable implication of Exceptionally Dispatching high heat rate units by submitting a self schedule for such resources is that the market clearing price does not accurately identify the true marginal unit and price it in the market accordingly," NRG reasoned.

"More to the point, it appears that the CAISO is using the Exceptional Dispatch mechanism to artificially depress energy prices, as well as issuing Exceptional Dispatch commitments to ensure system reliability," NRG added.

"These corrupted prices are particularly harmful to Market Participants seeking to enter into long-term power purchase agreements, bidding into Requests for Offers and other competitive procurements, or attempting to hedge their energy purchases. All of these critical market activities require accurate baseline pricing information, which the CAISO's routine use of the Exceptional Dispatch mechanism has distorted," NRG said.

NRG asked that the Commission and CAISO set forth a process immediately to price the Exceptional Dispatched resources into the CAISO markets, to at least provide for mitigation of the market effects while the CAISO works to analyze its operations and need for new products.

PG&E Asks to Delay Automated Data Exchange Application

Pacific Gas & Electric has asked for a two-year extension (until July 19, 2011) for the requirement to make an Automated Data Exchange application filing, citing ongoing work on standards which should occur before it designs its program (A. 05-06-028).

A 2006 California PUC decision related to PG&E's advanced metering deployment held that PG&E shall file an Automated Data Exchange application by July 19, 2009.

As proposed by several parties in the advanced metering docket, Automated Data Exchange would involve the following:

1) That hourly and daily electricity and gas data be posted to a data server in an open format immediately following retrieval and any necessary preprocessing;

2) That the data be accessible to customers and to qualified parties at the same time as PG&E's Information Technology systems gain access to the data, and

3) That qualified party access may be authorized either electronically or by a paper authorization with a "wet" signature from the customer.

Implementation has previously been delayed due to cost concerns.

PG&E said that an application should be further delayed because utilities and other stakeholders are currently engaged in a national effort to develop Automated Data Exchange standards, under the Utility Communications Architecture international users group. PG&E said moving forward with its application prior to the completion of national standards could make its program incompatible with such standards.

Briefly:

FirstEnergy Solutions Says Ohio Enrollments Under New Offer Exceed 10,000
FirstEnergy Solutions said it has lifted a 10,000 customer cap on its offer of a 10% discount off the Standard Service Offer price for customers at Ohio Edison, Toledo Edison, and Cleveland Electric Illuminating through 2009, reporting that it has signed more than 10,000 customers. FirstEnergy Solutions said the offer, with a discount of 5% in 2010, will still be available to customers contracting through July 13 (Matters, 6/30/09).

Duke Closes Pa. Wind Acquisition
Duke Energy said it closed on its purchase of the 70-MW North Allegheny Windpower Project in Pennsylvania from developer Gamesa Energy USA. The plant's output is contracted to FirstEnergy. Duke also said it is building a 51-MW wind farm in Burlington, Colo., with output sold to the Tri-State Generation and Transmission Association on a 20-year PPA.

Great Lakes Hydro Buys Affiliated Assets, Looks to Future Conversion to Corporation
Great Lakes Hydro Income Fund will buy nearly all of affiliate Brookfield Renewable Power's Canadian renewable power generation business for Canadian $945 million, in a move meant to position Great Lakes for a conversion to a corporation in 2011, when tax advantages for income trusts are to end. Both Great Lakes and Brookfield Renewable Power are subsidiaries of Brookfield Asset Management, and Brookfield Renewable Power owns 50% of Great Lakes. Great Lakes will also rename itself Brookfield Renewable Power Fund. Brookfield Renewable Power said going forward it will invest in Canadian contracted renewable power generating assets through the Fund as its exclusive platform for such investments. The projects being sold include 15 hydroelectric plants with a total installed capacity of 387 MW and a soon-to-be-constructed wind power project. Brookfield Renewable Power will also increase the price it currently pays for power generation from Great Lakes' existing Lievre and Mississagi power assets to reflect increases in power prices since the contracts were originally executed.

CPV ... *from 1*

However, CPV later admits in its filing that, "prices required to justify building a new natural gas plant are higher than short-term market signals for capacity and energy under the current PJM market structure," suggesting that any unquestionable savings are based on projections, and that the plant's costs today are higher than market prices.

Citing the Levitan & Associates report prepared last year on Maryland restructuring, CPV Maryland said that if the Commission orders the utilities to enter into 20-year contracts with a merchant facility, such as the St. Charles Project, ratepayers' overall power costs will decrease by an estimated $150-$400 million per year.

As it has said for the past year, CPV Maryland argued that since the collapse of the credit markets, "debt markets have required, and, for the reasonably foreseeable future unquestionably will continue to require, a fixed revenue stream of significant duration in order for lenders to finance new baseload or intermediate power plants in wholesale competitive markets such as PJM."

"In short, such plants simply won't be built absent the relative certainty that long-term contracts with creditworthy utilities can provide to satisfy lenders," CPV Maryland said.

CPV Maryland had to walk a delicate line in its filing. While quick to dismiss the possibility of new in-state capacity being built without long-term contracts, it was quick to oppose utility-owned generation as the solution to what CPV says is a broken market. Utility-owned generation would carry development risks, CPV Maryland said, with rate recovery commencing once construction (rather than commercial operation) starts, or perhaps even before construction.

"Ordering that power be purchased from CPV Maryland by means of a long-term contract would allow the Commission to shift away from Maryland's ratepayers and to CPV virtually all the risks of building the facility (including construction and operating cost overruns, construction and completion delays, and performance penalties such as those due to mechanical breakdowns, and failure to be available when called upon to deliver power," CPV Maryland claimed.

However, the PPA would be indexed to fuel prices which would be passed through to customers, although limited to a specific range. CPV Maryland is silent on what would happen to the ratepayer-funded capacity at the end of the PPA.

Under its proposed PPA, CPV Maryland would transfer its capacity to the utilities and provide the utilities the right to receive financial energy based on the variable costs of the St. Charles project without a profit margin. In return, the project will receive a capacity price based on a set price of dollars per installed kilowatt, derived directly from the project's cost data.

CPV Maryland would remain responsible for the physical energy product, and would bid physical energy every hour into PJM's advanced day-ahead markets. The utilities may elect to purchase financial energy priced at (i) scheduled quantity of energy times (ii) the difference between (a) the market price and (b) the variable costs for generating the energy, which will be set by the project heat rate times a transparent market fuel index (plus specific transportation charges) plus a per kilowatt-hour operation and maintenance charge and a start-up charge, if applicable. Thus, the PPA energy may at times be above or below market, with ratepayers either reaping the benefits or paying the costs.

CPV Maryland said that the PSC has authority to require its jurisdictional utilities to enter into long-term contracts, as Md. Code Ann., Pub. Util. Cos. § 7-510(c)(4)(ii)(B) allows the Commission to, "require or allow an investor-owned electric company to procure electricity for [residential and small commercial customers] directly from an electricity supplier through one or more bilateral contracts outside the competitive process."

The Commission's decision to order the PPA need not establish any new policy in favor of long-term contracts, CPV Maryland said, and the Commission could still address the issue comprehensively in Case 9117.

CPV asked for expedited approval of its request, as it is seeking a commercial operation date of June 1, 2012 and has several imminent financial milestones approaching.

FPO ... *from 1*

"It is imperative that the distribution utilities eschew radical and volatile changes that engender an unworkable competitive operating environment for ESCOs, their customers and all rate payers. It is of little comfort if the Companies do not offer an FPO commodity structure in 2010 but then in a year or so later decide that due to their assessment of the commodity markets they may be able to make additional profits by offering such a commodity product and therefore once again seek to change the existing commodity pricing structure by the intrusion of an FPO product offering by the regulated distribution utility," RESA continued.

"This interference with the commodity supply market ultimately creates an unstable and fragile competitive retail market. It is difficult for ESCOs to dedicate resources on a longer-term basis to a particular market when it is possible that the competitive offering from the utility can change drastically from one year to the next by replacing a market-bred based supply service with an FPO," RESA argued.

Accordingly, RESA asked that the Commission prohibit NYSEG and RG&E from re-introducing a fixed price option for five years, or until 2016. Any re-introduction of a fixed price option should require 12 months' notice, RESA said.

RESA also said that it is unclear whether the market-based supply service NYSEG and RG&E will offer starting January 1, 2010 will reflect actual or forecast costs, or if there is initially a forecast of the costs that is included in rates. RESA asked for clarification how the market-based supply calculation will be made, and that the utilities identify specifically how any forecasts will be developed and the method by which the forecasted results will be reconciled to the actual charges.

NYSEG and RG&E applied to remove ancillary services and the NYPA transmission adjustment charge (NTAC) from the nonbypassable rate, and to place such charges in the supply rate for customers purchasing utility supply. Accordingly, the utilities would no longer reimburse ESCOs for such costs, who will have to collect them directly from their customers as part of their rates.

While supporting the change, RESA asked that the modification be delayed until 2012, as ESCOs are serving customers on long-term contracts that did not include such charges in the rate, since such charges have always been reimbursed to ESCOs and have not been in the price to compare.