Energy Choice Matters

August 1, 2008

FirstEnergy Finds Security Plan More Favorable Than Market Pricing

Although also filing a Market Rate Offer (MRO), the FirstEnergy Utilities told PUCO that an Electric Security Plan (ESP) would be "considerably more favorable" to customers than market rates. Duke and AEP also filed ESPs; neither filed an MRO.

FirstEnergy ESP

FirstEnergy's three-year ESP (08-0935-EL-SSO) would cover all three of its Ohio distribution companies, Ohio Edison, Cleveland Electric Illuminating (CEI) and Toledo Edison, and would include increases in generation and distribution charges.

Compared with market rates, FirstEnergy calculated that the ESP would provide customers with a net present value exceeding $1.3 billion over the ESP period, or about $600 per customer.

Overall, increases in total customer rates - including generation, transmission and distribution - would be moderated to an average of 5.32% in 2009, 4.01% in 2010 and 5.99% in 2011.

The ESP would phase-in higher generation rates over a period of three years. The standard service generation offer would be 7.5¢/kWh in 2009, 8.0¢ in 2010, and 8.5¢ in 2011, but those prices would be mitigated by 10% annually.

Accordingly, the generation price paid under standard service in 2009 would be 6.75¢, increasing to 7.15¢ in 2010 and 7.55¢ in 2011. The average expected market price for 2009 would be 8.257¢/kWh, FirstEnergy said, while the current base generation rate is 6.8¢.

Generation charges and phase-in credits would be seasonally and voltage adjusted for all three years in retail tariffs. Recovery of the phase-in credits would occur over a period not to exceed 10 years, and the deferrals could be securitized. Recovery would be non-bypassable, except to certain

... Continued Page 4

Weaker Texas Mass Market Results Weigh Direct Energy Earnings

Direct Energy's operating profit for the first half of 2008 was down 18% to $181 million on weaker mass market results, though mass market customer count has improved since the end of fiscal 2007 and Direct's larger C&I unit reported stronger results. Revenues were up 19% to $4.9 billion.

Direct reported 3.0 million mass market customers as of June 30, down 5% from nearly 3.2 million a year ago. But Direct gained nearly 30,000 customers since the end of fiscal 2007, with growth in its Canadian and Northeast U. S. customer bases, as fixed price propositions became more attractive to consumers in an environment of rapidly rising energy prices.

Mass market revenue for the first six months of 2008 was up 3% to $2.7 billion, but operating profit for the unit fell nearly 30% to $122 million, mainly due to market conditions in Texas. Although bad debt was a "difficult issue" in U.S., bad debt levels were actually down 35% versus last year.

Operating profit at Direct's medium and large C&I unit rose to $16 million versus a loss of $2 million in the same period of 2007. With the acquisition of Strategic Energy, the unit serves 207,000 meters and has equivalent annual energy sales of approximately 55 TWh. Delivered electric volumes rose 41% to 9,228 GWh while delivered gas volumes rose 2% to 362 mmth. Revenue was up 48% to $1.4 billion. The Strategic acquisition contributed a loss after tax of about $6 million for the period from June 2 through June 30.

... Continued Page 4

Constellation Earnings Up on Higher Commodity Prices

Rising commodity prices lifted Constellation Energy second quarter profits 47% to $171.5 million from $116.3 million a year ago, with especially strong results in its international commodities business.

The customer supply business recorded higher gross margin of $277 million, versus $217 million a year ago, due to new business in retail gas.

Retail power retention, including customers renewing on month-to-month contracts, rose to 76%, and Constellation reported that, as in the first quarter, customers are still opting for short-term contracts due to high energy prices.

Constellation has not yet seen evidence of the cyclic recovery it expects in terms of customers returning to long-term electric contracts, which has left it behind expectations in its 2009 retail backlog. Constellation expects customer supply backlog of $113 million in the third quarter of 2008.

Second quarter as-priced margins were $2.49/MWh, down from $3.01 a year ago due to increased competition in Texas and New England, plus a product mix more heavily weighted to lower-margin contracts.

Retail gas retention hit 95%, and realized margins improved by 10¢/Dth over last year to 20¢/Dth, partially due to the Cornerstone Energy acquisition.

PUCT Denies TLSC/ROSE Emergency Rulemaking on Deposits, Switching Fees

The PUCT denied a petition from Texas Legal Services Center and Texas Ratepayers Organization to Save Energy for an emergency rulemaking to waive certain deposit requirements and switching fees for low-income customers of defaulting REPs, finding that the issues could be addressed in current cases involving POLR rules and REP certification (35868, Matters, 7/25/08).

Commissioner Paul Hudson agreed that the issues raised by the consumer groups were legitimate, but stated that adopting the groups' proposal could have unintended consequences.

Chairman Barry Smitherman pointed out that under the current POLR rules, deposits can be waived when customers have a two-year history of on-time payments, are 65 years or older, are medically indigent, or a victim of family violence.

Smitherman added that Oncor and CenterPoint, where most POLR-transitioned customers reside, do not have overly expensive out-of-cycle meter read fees, which must be paid to effectuate a quicker transition off the POLR. Smitherman noted the fee at CenterPoint is $6, while it's $7.25 at Oncor.

DPUC Allows Long-Term EDC Contracts for RECs from New and Old Plants

The Connecticut DPUC will allow electric distribution companies to sign long-term contracts for Class I RECs from both new and existing renewable generators, under an order issued yesterday (07-06-61, Matters, 7/11/08).

A draft decision would have limited long-term REC procurement to RECs from new facilities, but the Department agreed with Boralex's exceptions in which the generator argued that limiting REC contracts to new renewable energy sources could lead to pricing inefficiencies and artificial market distinctions (Matters, 7/15/08).

The DPUC affirmed that contracts shall be limited to RECs only, and shall not include energy or capacity procurements, despite pleas from United Illuminating to allow procurement of delivered energy and capacity on the REC contracts.

The Department will limit the contract length to not less than four and not greater than 10 years. Contracts must be for less than 50% of RECs needed to meet RPS.

All costs associated with the long-term REC contracts would be recovered through the generation service charge, as RECs would be used to meet EDCs' standard service and supplier of last resort RPS requirements.

The Department "strongly supports" an RFP procurement process, but will not preclude negotiated contracts, provided the EDCs submit sufficient documentation that meets a high burden of proof of favorable market conditions and ratepayer benefits.

Calif. PUC OKs Critical Peak Pricing as Default for PG&E C&Is Over 20 kW

The California PUC approved a decision that's to institute critical peak pricing as the default rate for Pacific Gas & Electric customers above 20 kW by 2010 (A. 06-03-005, Matters, 6/11/08).

Under the decision, large C&Is (200 kW and above) would be defaulted onto Time-of-Use rates with Critical Peak Pricing by May 1, 2010, and would not retain the option for simple Time of Use rates or a flat price. Large C&Is could elect real-time pricing once it is available (PG&E needs experience with the ISO's Market Redesign and Technology Upgrade before offering real-time pricing).

Medium C&Is (20-200 kW) would also default onto Time-of-Use rates with Critical Peak Pricing by May 1, 2010, but could opt onto simple Time-of-Use rates without a critical peak component. Medium C&Is would not have a flat price available.

Small C&Is (under 20 kW) would receive default Time-of-Use rates with Critical Peak Pricing by May 1, 2011. Residential customers cannot be moved to Time-of-Use rates per AB 1X protections, but will be able to choose TOU/CPP or real-time pricing.

AReM Argues ESP Bonding Rules Don't Belong in CCA Docket

The Alliance for Retail Energy Markets urged the California PUC to not consider Electric Service Provider bonding requirements in its current rulemaking on Community Choice Aggregator bonding levels (R. 03-10-003) because the scope of the docket does not include ESPs, and thus consideration of ESP bonding levels would violate due process.

SCE raised the issue of ESP bonding in comments, noting that the PUC has never found that current ESP bonding levels meet AB 117's requirement that ESPs and CCAs provide security to cover the payment of re-entry fees on behalf of customers that are involuntarily returned to bundled service (Matters, 7/21/08).

But AReM argued that ESP bonding rules should be left to the direct access rulemaking, and pointed out that no ESPs have been named as respondents to the CCA proceeding, nor has the Commission given any ESPs notice that ESP bonding requirements would be addressed in the proceeding.

AReM added that there is no compelling reason for the Commission to impose additional bond requirements on ESPs beyond the security deposit/bond requirements that are already applicable.

FPL Profits Hit by Mark-to-Market Losses

FPL Group's quarterly earnings dropped 48% to $209 million from $405 million a year ago, with a $157 million loss associated with the mark-to-market effect of non-qualifying hedges.

Competitive unit FPL Energy reported quarterly net income of $3 million, down from $203 million a year ago. Excluding the mark-to-market effect of non-qualifying hedges and other items, adjusted net income rose to $169 million from $146 million a year ago, mainly on new assets.

FPL Energy reported it's on target to add 1,200 to 1,300 MW of new wind assets this year and expects to add between 7,000 to 9,000 MW over the 2008 to 2012 timeframe.

Since a majority of FPL's merchant wind assets in Texas are highly hedged with power derivatives at the west zone through 2009, most exposure to market prices was mitigated. FPL noted lower ERCOT west prices were due to a significant number of major transmission line outages between the west and north zone for maintenance, higher than average wind resources resulting in higher wind generation, and a continued build out of new wind projects.

Briefly:

FERC Affirms Mexican Exports Won't Change Jurisdiction Over ERCOT

FERC affirmed in a declaratory order (EL08-71) that the transmission of electric energy over the Eagle Pass DC Tie, a transmission interconnection between ERCOT and Mexico's Comision Federal de Electricidad, will not affect the jurisdictional status of ERCOT or ERCOT electric utilities and Market Participants that are not currently public utilities. TexMex Energy, a power marketer formed for the exclusive purpose of purchasing wholesale power from the ERCOT region for export to Mexico, had requested the finding. TexMex is a wholly owned subsidiary of Protama, a Mexican corporation that develops energy projects.

E Source Acquires EnergyWindow

E Source has acquired online energy procurement specialist EnergyWindow, adding supply and risk management services to E Source's suite of energy conservation, management and sustainability offerings.

Dynowatt to Pay for REC Shortfall

Dynowatt d/b/a Accent Energy Texas entered into a settlement agreement with PUCT Staff (35942) under which Dynowatt would pay an administrative penalty of $550 relating to the REP's failure to retire 11 of the RECs it was required to retire for the 2007 compliance period. Dynowatt agreed to purchase and retire the requisite number of RECs as well.

83 REPs Agree to Pass Through Oncor Rebate

Oncor reported to the PUCT that 83 REPs have agreed to receive and completely pass through the one-time rebate customers are due from the $72 million credit Oncor offered in docket 34077. A listing of the REPs can be found in docket 35944.

Detroit Edison Benefits from Lower Choice Sales

DTE Energy reported on an analysts call yesterday that Detroit Edison's margin contributed $6 million to quarterly earnings as the expiration of the temporary show cause rate reduction and lower customer choice sales more than offset a reduction in sales due to milder weather and the impact of the economy. DTE will continue to see the benefit of the show cause related rate increase and lower choice volumes in the third and fourth quarters as well, it told investors. Still, operating earnings at the Detroit Edison utility were down at $51 million versus $64 million a year ago on storm costs and higher uncollectibles.

Direct Earnings ... *from 1*

Direct's home and business services unit grew customer accounts about 6% year-over-year, to 2.1 million, as a 13% rise in Canadian protection plan customers was mitigated by a dropoff in the U.S. residential new construction business related to the housing slowdown. Revenue was down 1% to $334 million while operating profit was flat at $6 million.

Power generation volumes in Texas fell by 8% to 2.3 TWh due to an unplanned two-week outage at the Bastrop Energy Center in June. Significant congestion in West Texas, due to maintenance outages on transmission lines, caused a sharp decline in achieved power prices for Direct's wind assets. Operating profit for Direct's wholesale unit (which also includes upstream gas assets) was down 5% to $37 million. While Direct's spark spreads this year in Texas have been somewhat below market, executives expect them to bounce back next year when hedges unwind.

Ohio ESPs ... *from 1*

governmental aggregation customers consistent with R.C. § 4928.20(1).

FirstEnergy offered to waive the collection of further regulatory transition charges (RTC) and Extended RTC charges for CEI customers (due to last through 2010), which would save customers over $500,000.

The base ESP generation prices also include all of the costs associated with the utilities' renewable energy resource requirements during the ESP period, and/or the equivalent cost for renewable credits.

The FirstEnergy utilities would also offer a Green Resource program, similar to that approved in Case No. 06-1112-EL-UNC, so that residential customers who desire to take steps above and beyond mandated requirements in support of renewable generation would have the option to do so through the purchase of renewable energy credits.

The ESP generation charge also includes a non-bypassable minimum default service charge for generation and administrative service under the ESP equal to 1.0¢/kWh as permitted by R.C. § 4928,143(B)(2)(d). Such a charge would be effective January 1, 2009 on a service rendered basis and is designed to compensate the utilities for the costs and risks associated with committing to obtain adequate generation resources to supply the entire retail load of customers in their service territories, a recognition of the risk and costs of customers switching to retail generation service provided by alterative generation suppliers at any time and in any amounts.

The security plan would establish Economic Development, Reasonable Arrangements, Demand Side Management and Energy Efficiency and Delta Revenue Recovery riders. The Economic Development rider would promote gradualism, recognize the efficient use of electricity, and mitigate overall bill impacts to customers through a series of credits and charges. Credits, if any, would only be available to customers taking SSO generation service from the utilities. The charges under the rider would be non-bypassable, and the discounts associated with the rider would be forfeited if a customer receiving the discount switches generation service to an alterative supplier.

The utilities would also establish a non-bypassable rider to recover the accumulated deferred balance of certain fuel costs as of December 31, 2008, stemming from the rate stabilization and rate certainty plans. Recovery would occur over a period not exceeding 25 years. Based upon a 25-year recovery period, the recovery factor for each of the utilities would be as follows: Ohio Edison 0.0375¢/kWh, CEI 0.0339¢/kWh, and Toledo Edison 0.0260 ¢/kWh.

Since the utilities would otherwise bear the risk of customer non-payment for non-distribution service, a non-bypassable Non-Distribution Service Uncollectible Rider would be established to recover non-distribution costs. Such a rider, effective January 1, 2009 on a service rendered basis, would be initially set at the average rate of 0.0403¢/kWh (composite of all utilities), but would be reconciled annually to reflect actual uncollectible non-distribution costs.

The security plan would permit all customers choosing competitive supply (not just governmental aggregators) to waive standby charges, with such customers paying market-based rates upon returning to the utility.

The ESP includes up to $25 million to support energy efficiency and demand response programs, $1 million toward an Advanced Metering Infrastructure pilot, and a commitment to undertake a comprehensive study of energy delivery system enhancement, including Smart Grid technologies. The utilities would also contribute $25 million for economic development and job retention.

The plan includes an arrangement with FirstEnergy Solutions for generation supply that provides for 1,000 MW of capacity additions.

The FirstEnergy utilities also proposed a short-term ESP that would last from Jan. 1 through April 30, 2009 to give PUCO more time to consider the ESP and MRO while giving customers price certainty ahead of January 1, 2009. The short-term ESP would need to be approved by November 14. The short-term ESP does not include all of the benefits of the full ESP and would include an average base generation rate of 7.75 ¢/kWh, mitigated to be 6.75¢.

FirstEnergy MRO

Under the proposed MRO (08-0936-EL-SSO), FirstEnergy would use a descending clock auction for full requirements service to set SSO rates that would be a three-year blend of laddered contracts.

After the initial laddering, FirstEnergy would hold two competitive solicitations, one in October and one in the subsequent January, which combined would procure 1/3 of the utilities' standard service needs annually. The delivery period would align with the June 1 start of the Midwest ISO planning year.

Seasonal pricing would apply to all residential and general service tariffs to send more appropriate price signals to customers, thereby encouraging customers to reduce usage during higher priced summer periods.

The MRO would also eliminate demand charges and the declining block structure from generation rates, to better align the way the utilities acquire power with how retail customers are charged for it.

Several non-bypassable charges, such as Rider RTC for previous rate transition credits at CEI, would still apply under the MRO. Rider CRT would also be unavoidable, and would collect certain incremental expenses associated with the implementation of the proposed competitive bidding plan including, (1) expenses not recovered through the tranche fees paid by wholesale suppliers, (2) a working capital adjustment to account for the lag between incurrence of SSO supply costs and collection of customer revenues, (3) uncollectible amounts associated with SSO generation service, and (4) the difference in revenue from the application of rates in the otherwise applicable rate schedule, including the Standard Service Offer Generation Charge, and the result of any economic development schedule, energy efficiency schedule, reasonable arrangement, governmental special contract, or unique arrangement (special contracts).

Duke ESP

Duke Energy Ohio's ESP (08-0920-EL-UNC) would last through Dec. 31, 2011 with an initial adjustment to prices by a total of 5.2%, or $110 million effective January 1, 2009. The proposed price adjustment includes projected increases to various generation components and the elimination of the residential regulatory transition charge. The estimated price proposal excludes adjustments for newly dedicated capacity, including renewable capacity, and the impact of distribution riders. Duke's ESP price adjustment includes a $20 million deferral to levelize the pricing impact associated with the different termination dates of the residential and non-residential regulatory transition charges, respectively.

The customer weighted average price to compare for the ESP is 6.7¢/kWh over the three years, or 6.25¢ for 2009, 6.73¢/kWh for 2010 and 7.15¢/kWh for 2011. Duke estimated a market rate would fall between 9.2¢ to 11.3¢.

Under the ESP, customers would be charged four base components:

(1) an avoidable Price to Compare charge to compensate DE-Ohio for several components such as: base generation; costs of fuel, emission allowances, energy from renewable resources, economy purchased power costs, congestion and losses, and financial transmission rights; environmental compliance costs, homeland security, and changes in tax law costs; and, a consumer price index adjustment to account for future inflationary pressures on the base generation component of Price to Compare;

(2) an unavoidable System Resource Adequacy (SRA) charge compensating DE-Ohio for market capacity purchases, the dedication of capacity for reliability purposes to retail load in DE-Ohio's certified territory, and capacity newly dedicated to retail load in DE-Ohio's certified territory, including capacity designed to produce renewable energy;

(3) an avoidable Transmission Cost Recovery tracker; and

(4) an unavoidable distribution component including three unavoidable distribution riders: (a) Rider DR-Infrastructure Modernization (IM) that includes charges to recover incremental costs associated with maintaining and modernizing distribution infrastructure, including SmartGrid investments, as well as the costs incurred to set up an Electronic Bulletin Board (EBB) to provide consumers with market choices; (b) Rider DR-Save-a-Watt (SAW) to provide compensation to achieve DE-Ohio's statutory energy efficiency mandates; and (c) Rider DR-Economic Competitiveness Fund (ECF) to assess prices associated with economic development and maintenance contracts approved by the Commission.

Duke claimed that the ESP "will continue the development of a competitive retail electric service market."

"The ESP will provide consumers with more choices and greater transparency regarding the SSO price, enhance consumers' ability to compare pricing, and facilitate the Commission's oversight of competitive prices," Duke said.

Duke's Rider PTC-BG (Price to Compare-Base Generation), which is currently known as "little g" or the unbundled generation price less regulatory transition charges, would be adjusted to compensate Duke for generation production, associated operation and maintenance, and dedication of existing generating assets including fuel. Thus it would include some avoidable capacity charges, as opposed to adjusting Rider SRA-Capacity Dedication, which Duke indicated was part of its "commitment to develop the competitive retail electric service market by minimizing unavoidable charges."

Duke also proposed moving its historical unbundled PUCO-approved fuel and emission allowance price from Price to Compare-Base Generation to Rider Price to Compare-Fuel & Purchased Power (PTC-FPP) in order to make prices relative to fuel, economy purchased power, NOx emission allowances, SO2 emission allowances, and other future allowances, including but not limited to potential allowances for carbon and mercury, more transparent for all consumers.

Since the term standby service isn't defined, Duke proposed crediting governmental aggregators 5% of their System Resource

Adequacy-System Reliability Tracker (SRA-SRT) and System Resource Adequacy-Capacity Dedication (SRA-CD) charges as a proxy for the "standby service" charge avoidable by government aggregators. If the aggregator's customers return to SSO, they must pay the "standby service" charge that they avoided as an ESP re-entry charge.

Duke would create an online electronic bulletin board to provide open access and information on pricing alternatives and energy cost information. Though thin on details, Duke said the EBB will be designed to provide competitive energy pricing alternatives to customers by publishing market based energy prices. The EBB website will also be made available, at a marketer's discretion, for the posting of competitive marketer prices, should a marketer opt to make their competitive prices available to customers.

Customer groups that can make use of the EBB will be established based on load profile analysis, where customers with similar monthly and hourly usage patterns will be grouped together. Alternatively, individual customers larger than 100 kW, with interval hourly meters, may request in writing that their accounts be specified individually, such that competitive marketer offers can be specifically made available for their inspection, and possible selection, thereby increasing the relevancy of the EBB to as many customers as possible, and insuring that competitive markets are "nurtured and supported through this transition period."

As part of the ESP, Duke requested approval to transfer its generating assets to its affiliate Genco. Upon approval, Duke would enter into a contract with Genco committing its generating assets, excluding those generating assets previously transferred to DE-Kentucky, that were used and useful prior to January 1, 2001, to serve load in its certified territory. DE-Ohio would enter into a wholesale power contract with the generation affiliates that provides DE-Ohio and consumers the same pricing as in the ESP.

AEP ESP

AEP Ohio submitted for its two utilities an ESP that limits rate increases to approximately 15% annually for the next three years (08-0917-EL-SSO). The ESP includes a fuel adjustment clause (FAC) which would be partially deferred to achieve the 15% limit in rate increases. Deferred FAC costs would be recovered with carrying costs over seven years from 2012 to 2018.

AEP projected that full requirements, market generation prices would be 8.532¢/kWh for Ohio Power and 8.815¢/kWh for Columbus Southern Power.

The ESP would include a non-bypassable Provider of Last Resort Rider for standby service to reflect the costs related to the optionality associated with the utilities meeting their POLR obligation.

While statute requires governmental aggregators to avoid standby charges, AEP would not extend that benefit to individual shoppers, because it fears that, even if its tariff required shoppers bypassing the standby charges to pay market-based rates upon returning to POLR service, policymakers would intercede to protect customers from market prices in such circumstances.

"I simply do not believe that the Commission and/or the General Assembly and Governor will sit back and fail to intervene while residential customers are forced into paying those [higher market] rates," J. Craig Baker, Senior Vice President for Regulatory Services at AEP, testified.

Baker noted SB 221, which created the ESPs, was itself a reaction to the threat of higher market prices, and convinces him, "that utilities likely would not be permitted to charge market rates to those customers who agreed to forego standby service."

Baker is "quite confident" that customers returning to POLR service would not be required to pay peak spot market prices.

Baker argued that, "such one-sided rights that customers receive through retail choice are equivalent to a series of options on power," and thus the proposed POLR charge is a "fair and reasonable" approach to addressing the inherent risk associated with acting as the POLR.