Energy Choice Matters
August 3, 2009

First Choice Power Reverses Year-Ago Loss on Higher Margins

Higher margins and a change in customer mix drove a continued turnaround at First Choice Power, which recorded second quarter ongoing earnings of $12.6 million, compared with losses of $13.0 million a year ago. GAAP earnings were $16.0 million versus a loss of $60.4 million a year ago.

Lower wholesale prices and reduced market volatility, along with efforts to change the customer base, resulted in second quarter margins in the low $40/MWh range. Jeff Sterba, CEO of parent PNM Resources, stressed that margins are expected to compress in the third and fourth quarter, both from competitive pressure pushing retail prices down, and from expected higher wholesale prices (and associated volatility) indicated by the forward curves. More typical margins (mid $20/MWh) are expected by 2010. Though slightly compressed, margins in July stayed "reasonably strong," Sterba said.

The benefit from higher unit margins was partially offset by a drop in sales volume, primarily resulting from a lower customer count. With First Choice's focus on attracting and retaining quality customers, the REP is being considerably more selective in its marketing efforts.

Customer count was 243,300 versus 253,800 last year, but up versus 237,400 at the end of 2008. First Choice expects customer count to remain below last year's quarterly level during the rest of the year.

First Choice's customer mix has grown from 40% on term contracts a year ago to over 75%. After results in the first half of 2008, First Choice now tries to keep its book as flat as possible, and is nearly 100% hedged for residential term customers. The REP has also increased its commercial portfolio in an effort to reduce bad debt.

Bad debt expense increased $1.1 million to $10.1 million for the quarter, but the increase was

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Michigan Staff Suggest Extended Rescission Period, Exit Fee Cap for Gas Suppliers

Competitive gas suppliers in Michigan would be subject to a rescission period that extends beyond the first bill; caps on termination fees and product length; a requirement to compare their fixed rate to the utility rate; and a host of other new consumer protection rules under proposed revisions to the LDC choice tariffs submitted by Michigan PSC Staff (U-15929, Matters, 4/17/09).

Under Staff's proposed changes, the customer's unconditional right to cancel a contract would extend 10 days beyond the due date of the first natural gas bill listing the supplier's charges. The extended rescission period would apply to all customers, and customers could invoke their rescission right via written or verbal communications. A customer canceling the contract during the rescission period would be treated as though the customer had never enrolled with the supplier.

Residential and small commercial customers currently have a 30-day unconditional cancellation period to cancel a supplier contract. "Over time, Staff has learned that many residential and commercial customers do not fully understand a [choice] contract until they receive the first bill where the Gas Cost Recovery (GCR) utility rate is replaced with the Supplier's name and the contracted rate," said PSC departmental analyst Sheila Cornfield on behalf of Staff.

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FirstEnergy to Seek Approval to Move Ohio, Penn Power Service Areas from MISO to PJM

In a move FirstEnergy claimed would benefit customers, FirstEnergy said it intends to move its Ohio and Penn Power transmission assets from the Midwest ISO into PJM, where any generation in those service areas would benefit from a centralized capacity market and generally higher energy prices.

"Aligning all of our transmission assets with PJM will provide customers with the benefits of a more fully developed retail choice market and enhanced long-term planning that supports construction of new generation when and where it is needed," said FirstEnergy CEO Anthony Alexander.

"PJM is a better fit for our competitive focus," Alexander added.

Making the move to PJM would be assets owned by FirstEnergy's American Transmission Systems subsidiary, which includes transmission assets within the service territories of Ohio Edison, Cleveland Electric Illuminating, Toledo Edison and Penn Power. FirstEnergy's Met-Ed/Penelec and Jersey Central Power & Light assets are currently in PJM.

FirstEnergy said American Transmission Systems is a better fit with PJM operationally, with 32 interconnections with PJM compared to just three with MISO.

"The consolidation into PJM also would provide greater access to merchant generation, resulting in enhanced flexibility to meet customers' electricity needs," FirstEnergy said.

In a news release, FirstEnergy said, "PJM operates within a largely deregulated region and its market rules are designed to better accommodate retail electric competition." While serving load in PJM is operationally easier for retail suppliers than MISO, much larger barriers to retail competition in the Ohio FirstEnergy territories exist, including continued nonbypassable charges related to generation costs.

Some Wall Street analysts have called the lower than anticipated price ($61.50/MWh) resulting from the FirstEnergy Ohio utilities' May competitive procurement a poor result for FirstEnergy's competitive arm, especially as FirstEnergy Solutions only secured 51% of load (versus 75% in the interim procurement). FERC also recently denied a petition from FirstEnergy Solutions for a declaratory order authorizing PJM to convert a 1,000 MW firm point-to-point service reservation to a comparable network integration transmission service reservation.

FirstEnergy hopes to obtain FERC approval for the transfer so that the American Transmission Systems assets can be integrated into PJM on June 1, 2011.

Dominion Retail Earnings Fall

Dominion Retail's Earnings Before Interest & Taxes for the second quarter fell to $14 million from $24 million a year ago, parent Dominion Resources said Friday. On an after tax basis, Dominion Retail's contribution to its parent was $7 million lower year-over-year.

Dominion Retail's average customer count during the second quarter grew to 1.725 million from 1.597 million a year ago. Gas accounts increased to 654,000 from 594,000 a year ago, and electric accounts grew to 421,000 from 298,000 a year ago. Products and Services customer count fell to 651,000 from 706,000 a year ago.

In the second quarter, Dominion Retail saw a $102 million increase in electricity sales versus the year-ago period, with a $70 million increase from the Cirro Energy acquisition, and a $40 million increase resulting from higher sales volumes, partially offset by lower sale prices ($8 million). Dominion Retail's quarterly natural gas sales decreased $54 million year-over-year, primarily due to lower prices.

Dominion Retail electric volumes for the second quarter were 1.80 million MWh versus 759,000 MWh a year ago. Gas volumes were 14,800 mmcf versus 16,700 mmcf a year ago.

Dominion Generation's EBIT from merchant assets was up at $333 million versus $134 million a year ago, due to higher margins. EBITDA for NEPOOL merchant assets was up at $333 million from $177 million a year ago, while EBITDA from PJM assets was up at $19 million versus $4 million a year ago.

Lower Volumes Offset Higher Margins at Constellation Customer Supply Unit

Adjusted earnings at Constellation Energy's merchant unit were down for the second quarter at $205 million from $313 million a year ago, mainly from a reduction in trading activities and divested operations. GAAP merchant earnings were about $4 million, down from $281 million a year ago.

Constellation's customer supply unit was flat year-over-year, as lower operating costs and earnings from the sale of wholesale contracts were offset by lower wholesale volumes. Though Constellation saw "strong" margins in its customer supply business, demand destruction offset such gains. CFO Jack Thayer said Texas is the only region where customer supply is not seeing significant demand destruction. CEO Mayo Shattuck credited increased customer supply margins to the exit of several players from the retail and wholesale business.

Shattuck said Constellation expects its open owned and contracted generation to align with approximately 65% of its total fixed priced wholesale and retail load obligations for 2009. Moving forward, Constellation will continue to focus its customer supply operation on markets with strong merchant generation footprints, where it can augment its generation assets by contracting for offtake agreements.

"As we move forward, we expect to further align our load obligations by buying attractively priced generation assets and entering into longer dated offtake agreements with merchant generators. This will reduce our dependence on exchange traded products, lowering collateral requirements and further enhancing the returns of our generation and customer supply operations," Shattuck said.

Adjusted customer supply gross margin was $251 million versus $277 million a year ago. Retail electric gross margin was about $7/MWh, up from about $2.50/MWh a year ago. Retail gas gross margin was about 27¢/Dth, up from about 21¢/Dth a year ago.

Constellation's retail electric customer retention rate (including month-to-month customers) was up at 70% versus under 50% at the end of the first quarter. The retail gas retention rate was relatively flat versus the first quarter at just under 95%.

Constellation said it sells over 1 million RECs to commercial and industrial customers each year, and currently has 500 customers, with 850 megawatts under contract, in its demand response program. Constellation is also working to develop environmental risk management products for the NYMEX Green Exchange.

Constellation's merchant generation unit contributed about $86 million in higher earnings versus the second quarter of 2008, from about $36 million in higher margins and about $50 million from fewer outages. Generation adjusted gross margin was higher at $482 million versus $365 million a year ago.

Sempra Commodities Earnings Lower on Flat Power, Gas Results

Sempra Commodities reported lower second-quarter earnings of $85 million, versus $130 million a year ago, reflecting Sempra's share of $142 million in distributable income from the RBS-Sempra Commodities joint venture.

The year-ago earnings benefited from a $67 million gain on the sale of the business to the joint venture with RBS, partially offset by $30 million in charges for litigation and tax matters.

Weak wholesale natural gas and power prices, as well as reduced volatility, led to flat results in the joint venture's two largest business lines (gas and power).

Low natural gas prices coupled with exceptionally low basis differentials across the country have reduced the number of profitable trading opportunities. Sempra does not expect improvement in the third quarter, as it is traditionally a slow quarter for trading, but is anticipating a change in the currently "tough" environment by the fourth quarter. RBS-Sempra's oil and metals businesses continue to do well.

Sempra CEO Donald Felsinger forecast minimal impact on RBS-Sempra should the U.S. Congress tighten regulation of commodities markets, since the joint venture is heavy on physical delivery of commodities, and hedging activities for customers (such as producers and power plants) that need to hedge their supplies or hedge their purchases. CFO Mark Snell said Sempra "pretty much" supports proposed activities around more transparency and the elimination of systemic risk.

Sempra Generation quarterly earnings were up at $33 million from $23 million a year ago despite $8 million in lower earnings from operations as the result of lower market prices. The year-over-year increase was largely driven by $23 million in improved mark-to-market earnings on forward contracts with RBS-Sempra Commodities and other counterparties, as a $20 million loss in 2008 was reversed.

Higher BGS Prices, Dispatch Changes Lift PSEG Power Earnings

PSEG Power posted higher operating earnings of $238 million for the second quarter of 2009 compared with operating earnings of $216 million a year ago on higher margins.

Margin growth was driven by higher contracted pricing (including higher BGS auction prices and the rolloff of a below-market contract) and lower fuel costs. PSEG Power met reduced load obligations in the quarter with higher output from its nuclear fleet, which supplied 62% of generation in the quarter compared with 52% in the year-ago quarter. A reduction in the price of gas continued to support operation of the combined cycle gas-fired fleet at the displacement of coal-fired stations. Gross margin improved to $63/MWh from $50/MWh a year ago.

PSEG Energy Holdings, which includes ERCOT assets, reported lower operating earnings of $36 million for the second quarter of 2009 versus operating earnings of $50 million a year ago. Operating profit from Holdings' 2,000 MW of gas-fired generating capacity in Texas declined by amount $30 million as reduced demand and lower energy prices more than offset a reduction in maintenance expense and lower financing costs associated with the Texas assets.

PSEG also disclosed that its PSEG Energy Resources and Trade unit won several tranches in PECO's recent default service auction. PECO announced that only two suppliers (among 11 competing) won load in the residential procurement. Exelon Generation had previously announced it had won tranches in the auction.

CMP to Prorate Standard Offer, T&D Arrearages as Interim Solution

Central Maine Power has proposed to prorate Standard Offer and Transmission and Distribution arrearages starting with bills for the month-end of July 2009 as an interim solution until it can implement a permanent solution to ensure that the oldest charge is paid first.

As only reported in *Matters*, the Maine PUC found that CMP's current payment processing order did not comply with applicable rules. The Commission requires that the older of Standard Offer and Transmission and Distribution charges must be paid first. If Standard Offer and Transmission and Distribution charges are the same age, then Transmission and Distribution charges are paid first (Matters, 5/21/09).

CMP, however, used a vintaging process in its billing system which placed arrearages into four buckets: current; 30-day; 60-day; and 90 or more days. The process treated any arrearage older than 90 days as the same age, prompting newer Transmission and Distribution charges to be paid before older Standard Offer arrearages.

To comply with the Commission's order, CMP intends to create an unlimited number of "virtual" vintage aging buckets within its billing system so that newer Transmission and Distribution charges do not leapfrog older Standard Offer charges. However, implementation will take six to nine months.

In the interim, CMP said it will allocate 90+ day arrearages on a pro rata basis between Standard Offer and Transmission and Distribution charges. CMP will aggregate partial payments of that vintage, segregated by class (Residential, Small General Service, and Medium and Large General Service), including payments on active and previously charged off accounts. CMP will then recalculate the Standard Offer and Transmission and Distribution partial payments based on the T&D and Standard Offer price proportions in effect for the four to six months prior to the month that the accounting entry is booked. CMP will then allocate partial payments according to these price proportions.

IESO Markets Perform "Reasonably Well"

Markets administered by Ontario's Independent Electricity System Operator performed "reasonably well" over the six-month period November 2008 to April 2009, the Ontario Energy Board Market Surveillance Panel said in a report.

The surveillance panel did not find gaming or abuse of market power to be occurring, with the possible exception of one matter that is still being assessed.

During the November 2008 to April 2009 period, the average Hourly Ontario Energy Price (HOEP) of $40.98/MWh was substantially lower (17%) than last year because of a number of factors including lower demand for electricity and improved baseload supply. However, the effective load-weighted HOEP after uplifts and the Global Adjustment increased by 7% to $58.08/MWh.

Since the New York ISO obtained a prohibition on the scheduling of certain linked-wheel transactions in July 2008 from FERC, including scheduled linked-wheels originating in New York and destined for PJM (through Ontario and the Midwest ISO), Ontario export volumes to PJM have steadily increased and reached a monthly peak of 1.02 TWh in March 2009.

Under a preliminary review, the Market Surveillance Panel has observed that the increased Ontario exports to PJM through MISO have induced a significant portion of parallel path flow (loop flow) from west to east within Ontario and on the Ontario-New York intertie. The preliminary findings show that unscheduled flows resulting from Ontario exports to PJM are not leading to significant amounts of internal congestion and therefore, Ontario has not experienced the type of adverse impacts that occurred in New York last year. However, further review is still needed to assess congestion at the New York intertie itself, the surveillance panel said.

Calpine Earnings Lower on Reduced Margins

Calpine reported adjusted EBITDA of $457 million for the second quarter of 2009, down from $479 million a year ago, mainly on lower margins from its Texas and West assets.

Calpine recorded a second-quarter net loss of $78 million versus income of $197 million a year ago, on the margin decline as well as reorganization items, one-time items such as debt extinguishment costs, and mark-to-market impacts. Excluding these three latter items, net income was $49 million for the 2009 quarter, versus $81 million a year ago.

Commodity Margin decreased from $675 million in the 2008 quarter to $650 million in 2009. Texas commodity margin fell to $196 million from $215 million a year ago, while the West margin fell to $304 million from $315 million a year ago. Both decreases were due to lower market spark spreads given lower power demand and lower natural gas prices. Commodity Margin in Calpine's Southeast and North regions was essentially flat.

FERC Denies Rehearing of FirstEnergy Affiliate Waiver Provision

FERC denied a rehearing request regarding affiliate waivers approved in December as part of FirstEnergy's renewed market-based rate authorization, in an order that sidesteps a concern raised by the Public Utilities Commission of Ohio (Matters, 1/23/09).

In its December order, FERC approved a waiver which allows FirstEnergy Solutions and other merchant affiliates to sell energy and capacity to FirstEnergy affiliated utilities in Ohio without prior FERC approval.

While PUCO did not initially object to the waiver, the FirstEnergy utilities' decision to withdraw their original electric security plan, after PUCO modification, prompted PUCO's rehearing request. PUCO argued that while a waiver is not problematic so long as the FirstEnergy utilities' supply procurement and retail rates are set pursuant to either an electric security plan or market rate offer (in which either case PUCO reviews either the rates themselves or the market process which sets rates), the utilities' "backstop" procurement necessitated by withdrawal of the electric security plan fell outside of any state commission review. Accordingly, federal review of affiliate transactions is warranted, PUCO said, arguing that the blanket waiver in the market-based rate tariffs should be removed.

FERC dismissed such concerns, reiterating that as a customer choice state, FirstEnergy Ohio utility customers are not captive, and an affiliate waiver is appropriate.

Furthermore, FERC said that even if customers were considered captive, "Ohio has a state-mandated procurement process that is subject to the oversight of the Ohio Commission," adding that, "The Ohio Regulated Utilities' ability to implement either a market rate offer or an electric security plan is dependent on approval by the Ohio Commission."

However, such reasoning ignores the essence of PUCO's rehearing request, which is that under certain circumstances, the two procurement alternatives listed by FERC may be bypassed, as was in the case in the utilities' December 2008 backstop procurement.

"We find that the Ohio Commission's approval in its recent decisions indicates that the Ohio Commission now has, and will continue to have, the ability to ensure a properly developed procurement plan and to oversee a fair administration of such a plan in order to protect retail customers," FERC said, though under current market design, another backstop procurement is possible should a new electric security plan or market rate offer not be in place at the end of the current plan which expires May 2011.

Briefly:

Vectren Source Reports Seasonal Loss, Customer Growth

Vectren Source reported a seasonal loss of $1.7 million for the second quarter of 2009, compared to a loss of $1.2 million a year ago. Vectren Source's customer count at June 30, 2009 was approximately 182,000, up from 152,000 a year ago and 171,000 at the end of the first quarter of 2009. Vectren said that it expects the record margins seen in the first quarter, due to commodity prices falling faster than retail pricing, to compress by the fourth quarter as commodity prices remain low, and competitive pressures reduce margin opportunities. Vectren Corp.'s ProLiance unit posted a seasonal loss of $2.7 million (excluding a Liberty storage charge) versus a loss of $4.4 million a year ago.

Volunteer Offering Ohio Electric Aggregation

Volunteer Energy says it has expanded its electric aggregation program to Ohio, focused on commercial customers with a minimum load profile at the FirstEnergy utilities and Duke Energy. "This really is the first time in Ohio that a significant gap has opened up in wholesale electric rates," said Richard Curnutte Sr., President of Volunteer Energy.

TXU Files to Continue as Volunteer POLR

TXU Energy filed at the PUCT to continue as a volunteer POLR for the residential, small non-residential and medium non-residential classes in all service areas. TXU had previously been accepted as a volunteer POLR for the 2009-2010 term, but its filing is prompted by a request for volunteer POLRs due new POLR rules adopted in project 35769.

Tenaska Power Services Challenges TPS Power Holdings' Name

Tenaska Power Service Co. urged the PUCT to dismiss the application of TPS Power Holdings, LLC, for a REP certificate, on the basis of the start-up's similar name. As only reported by *Matters* when TPS Power Holdings first sought certification, Tenaska Power Services uses the trade name "TPS I" and similar names for its Option 2 REP (Matters, 5/21/09). Staff has also moved to dismiss the currently abated application docket without prejudice due to insufficiencies in the application which have not been corrected in the moth-long period of abatement.

Columbus Southern Power Seeks Rehearing of Waterford, Darby Order, Requests Authorization to Transfer Plants

Columbus Southern Power filed for rehearing of the Public Utilities Commission of Ohio's recent electric security plan rehearing order, which disallowed costs related to the Waterford and

Darby generating facilities. Columbus Southern Power argued that the Commission should authorize the sale or transfer of the facilities since Columbus Southern Power may no longer recover its customers' jurisdictional share of the costs of the plants.

Nicor Competitive Units' Operating Income Rises

Operating income from Nicor Inc.'s other energy ventures increased $1.7 million for the second quarter of 2009 to $12.7 million, due primarily to higher operating income at Nicor's energy-related products and services businesses ($1.4 million increase) and at Nicor's wholesale natural gas marketing business, Nicor Enerchange ($0.2 million increase). Higher operating income at Nicor's energy-related products and services businesses was due to a $1.6 million decrease in operating expenses, driven by lower average cost per utility-bill management contract. These gains were partially offset by $200,000 in lower operating revenues for energy-related products and services. Higher operating income at Nicor Enerchange was due primarily to favorable changes in valuations of derivative instruments used for hedging, partially offset by unfavorable costing of physical sales activity and lower results from the company's risk management activities associated with hedging the product risks of the utility-bill management contracts offered by Nicor's energy-related products and services businesses.

HSBC Seeks Illinois Electric License

HSBC Technology & Services applied for an alternative retail electric supplier license in Illinois to self-supply HSBC Bank facilities. ECM Energy Management Services will serve as HSBC's vendor for various technical services.

AEP Generation and Marketing Earnings Fall

AEP reported ongoing quarterly earnings for Generation and Marketing of $4 million, down from $26 million a year ago, due to lower gross margins from marketing activities, lower power prices in ERCOT, and an extended planned outage at the Oklaunion Power Station. Earnings from wind farms were lower as a result of decreased wind generation and increased curtailments.

FERC Approves SPP Queue Reform Plan With Changes

FERC largely accepted the Southwest Power Pool's interconnection queue reform proposal, though it ordered several modifications (ER09-1254). Among them is that SPP may not retain the unused study deposits upon a project's suspension or withdrawal during or after the facilities study, aside from retaining the costs needed to conduct the studies for the project and any restudies caused by the suspension or withdrawal. Remaining funds are to be refunded to the developer. Additionally, FERC directed SPP to offer a cure period to allow developers to correct deficient filings regardless of when a customer submits its interconnection request during the 180-day cluster window. FERC also imposed various reporting requirements on SPP.

PJM Submits Compliance Filing on Opportunity Costs

PJM submitted a compliance filing containing tariff revisions to include opportunity costs for energy and environmental limitations in mitigated offer prices (ER08-47, Matters, 5/29/09). PJM said that a stakeholder process will review what, if any, additional opportunity costs should be included in mitigated offers, with a FERC filing expected in July 2010.

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smaller than has been seen in recent quarters. Executives said various measures, including changes to the customer mix and increasing its focus on customer credit standards, are beginning to show results. Still, executives said it is too early to determine whether such steps will continue to show positive results in the coming quarters, and said bad debt remains too high. As a percentage of revenues, bad debt was 7%, versus 12% in recent quarters. Operating revenues were $138.0 million, with residential sales accounting for $92.8 million of that total.

Sterba encouraged the PUCT to implement a customer bill payment history database, noting REPs are willing to fund the database (rather than funding the costs through a nonbypassable surcharge), and noted it would save REPs more in bad debt costs than it would cost to implement, meaning customer rates will be reduced as higher bad debt costs are stripped out of pricing.

Sterba said that the database, by indicating customers with poor payment history, can help REPs, "take appropriate action on either pricing or deposit or waiver of providing service to that customer."

First Choice ongoing EBITDA was $21 million for the quarter, up substantially from a loss of $19 million last year. The improvement was mainly driven by increased margins, which were up $44 million quarter over quarter. Bad debt ($1.1 million higher) and marketing initiatives ($1.4 million higher) reduced ongoing EBITDA by $2.5 million.

PNM Resources' equity in Optim Energy's quarterly net ongoing earnings was $0.3 million, compared with $2.7 million in 2008. PNM Resources' equity in the net GAAP losses of Optim Energy was $4.4 million, compared with losses of $1.5 million in 2008. Depressed electricity prices, coupled with costs associated with outages at the Twin Oaks Power facility, reduced results.

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Additionally, Staff recommended that early termination fees for residential and small commercial contracts of one year or less should be capped at $50. Termination fees for residential and small commercial contracts of longer than one year shall not exceed $100 under Staff's proposal.

"Staff recommends that termination fees and contract duration be capped as a result of numerous customer complaints. Staff has found that long-term contracts together with large fees actually discourage customer choice and foster discontentment with the [choice] program," Cornfield said.

"Staff believes that a cap on contract duration and termination fees is of critical importance to the long-term sustainability and success of the [choice] program," Cornfield added.

Customers would be able to leave their supplier regardless of whether they have paid contractual termination fees. The supplier would be prohibited from preventing any switch on the basis of an unpaid termination fee or other penalty.

Cornfield recommended that the maximum product length be limited to two years, though service could continue thereafter on a month-to-month basis, provided that the customer may cancel without penalty after the two years expired.

All variable priced products would be required to disclose in contracts and marketing materials a "clear explanation" of the "pricing factors" used to determine the price, and example of how the pricing factors would be implemented.

All contracts must be provided to the customer with all rates, terms, and conditions considered part of the contract included in one document, under Staff's proposal.

Furthermore, Staff recommended that for suppliers offering a fixed price product whose initial price is higher than the current utility GCR rate, the supplier must disclose to the customer during the solicitation that the fixed rate is above the utility's current GCR rate.

Suppliers using telephonic enrollment would be required to record the entire sales call in addition to using third party verification of enrollment.

Staff would prohibit supplier agents from removing a residential or small commercial customer's bill from their home/office. Suppliers would be required to comply with "truth in advertising."

Customers switching from a competitive supplier back to the LDC would be forced to stay with the LDC for a minimum term of 12 months. Staff would also remove the current, "unenforceable" provision which requires customers to remain on competitive supply for 12 months when leaving the LDC.

Under Staff's proposal, the fixed-price contract expiration notice required if there will be a price change at the end of the contract must be sent 60 days prior to expiration, rather than 30 as in the current tariffs.

Suppliers would be required to submit for Staff review any residential or small commercial contracts, scripts or marketing materials at least five days before use. Currently, only residential contracts must be submitted for review.

Staff's proposal holds that suppliers must send a confirmation letter to the customer within seven days of the customer signing a contract.

Suppliers would be compelled to maintain verification records for three years beyond the end of a customer contract.

Only a "legalized authorized person" could sign a supply contract, defined as a person with legal documentation or legal authority to enter into a binding contract (such as an individual with power of attorney or an authorized corporate agent). A customer's spouse would not be presumed to be a legalized authorized person.

Staff believes the legalized authorized person requirement is, "critically important as Staff has been made aware of individual enrollments that were signed by babysitters or visiting relatives and business accounts enrolled by employees without legal authority."

Staff's revised tariffs would hold that the Commission and Staff would be solely responsible for monitoring and enforcement.