Energy Choice Matters

January 7, 2010

Cold Weather Prompts Suspension of Disconnects for Non-Pay in ERCOT

Severe cold weather in Texas has prompted the Transmission & Distribution Utilities to suspend Disconnects for Non-Pay, per PUCT rules. Per Subst. R. §25.483 (i)(1)(A), an extreme weather emergency includes a day when the previous day's highest temperature did not exceed 32 degrees Fahrenheit, and the temperature is predicted to remain at or below that level for the next 24 hours anywhere in the county, according to the nearest National Weather Service reports.

Oncor noted that the temperature is projected to drop below 32 degrees throughout all of the Oncor service territory by daybreak on January 7th and is projected to remain under 32 degrees on January 8th. Oncor will suspend Disconnect for Non-Pay activity on January 8th. Based upon projected weather forecasts, Oncor expects to resume working Disconnect for Non-Pay orders on Monday, January 11.

The entire CenterPoint Energy service territory is under a National Weather Service Hard Freeze Warning through 9:00 AM January 10th. Some parts of Southeast Texas will likely endure 48 to 60 consecutive hours of sub-freezing temperatures during this period, CenterPoint said in a market notice. Therefore, CenterPoint will stop the field execution of any Disconnect for Non-Pay transactions on January 7th and January 8th. Current transactions in its systems will be cancelled, and REPs may submit new DNP transaction requests for dates starting January 11th. CenterPoint said that the decision to suspend DNPs starting January 7th was also driven by its need to dedicate field personnel to the safe and reliable operation of the electric system during this period of extremely

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Suppliers, Customers Urge Front-End Loading of Expanded Calif. Direct Access

The phase-in of expanded direct access in California should be implemented using a front-end loaded schedule that will provide more customers with the early opportunity to initiate direct access (DA) service, the California Alliance for Choice in Energy Solutions and the Alliance for Retail Energy Markets said in comments at the PUC (R. 07-05-025, Only in Matters, 1/6/10).

"[G]iven that interest in Direct Access service is likely to be highest in the period immediately following the reopening, the front-end loaded schedule will serve to reduce the possibility that customers who are interested in returning to Direct Access will be precluded from doing so due to the cap. [B]ecause the overall growth in DA load is relatively small, the impact of a front end loaded phase-in versus a more even phase-in will be minimal, if there is any demonstrable impact at all," CACES and AReM said.

CACES and AReM suggested a schedule allowing up to 75% of the cap to be reached in the first year, up to 90% of the cap in the second year, and up to 100% of the cap in the third year. A front-end loaded schedule will also allow electric service providers to take advantage of economies of scale, AReM and CACES added.

As noted above, CACES and AReM proposed that the increase in direct access permitted each year should be expressed as a maximum percentage of the cap that is allowed in each year of the

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Direct Energy Home Energy Manager Pilot to Initially Include 40 Customers

Direct Energy's previously reported pilot for its new Home Energy Manager will initially be offered to 40 customers in the CenterPoint territory of Houston, David Dollihite, vice president of product development at Direct Energy, confirmed yesterday (Only in Matters, 1/1/10).

As first reported by *Matters* last week, the Home Energy Manager results from a collaborative with Whirlpool Corporation, Best Buy, Lennox International, and OpenPeak.

Aside from the installation of advanced meters at CenterPoint, the service territory was selected in particular because of CenterPoint's use of Itron meters, and Itron's partnership with OpenPeak.

Dollihite said that the pilot is anticipated to last one year, but Direct could accelerate commercial rollout of the Manger if customer demand warrants it. The pilot is focused on consumer behavior, viability, and acceptance of the Manager, rather than technical interaction among the Manager and various smart grid components and appliances, Dollihite added.

While Best Buy's Geek Squad will facilitate installation, Direct will initially supply the Manager. Sales through Best Buy will depend on the viability of the manger after the pilots.

The Manager, which will be branded with Direct's logo on screen, is slightly larger than a smart phone, and uses a touch screen interface. As previously reported, the Manger allows the customer to access other online content, such as news, weather, video, and social networking sites, to attract customers to the Manager.

The Manager will allow customers to track usage in real-time, and adjust smart appliances in response to usage and prices. Among other things, the Manger will list the customer's electric usage and spend to date, projected spending versus a monthly budget, days left in a billing cycle, pricing and contract information, and various suggestions to reduce energy usage and keep customers under their target budgets (click link for screenshots)

Dollihite hopes that the manager serves as another step to transform electricity from a commodity to a consumer product, in which consumers have a variety of choices. The Manager will include an online application store where consumers can download applications relevant to their lives at home, and also build on the platform.

The Manager evolved from other Direct pilots to bring energy information to consumers. Last year, Direct showcased a set-top box home energy management dashboard that included much of the same information as the Manager (Only in Matters, 4/2/09). Dollihite noted that the screen on which consumers prefer to read information is generational, with older customers preferring the television, middle-aged customers opting for a personal computer, and the youngest customers using a mobile device.

BidURenergy.com Confirms National Expansion Plans

The New Jersey, Pennsylvania, Illinois and Massachusetts gas and electric markets are among the priority markets BidURenergy.com will enter as it expands from its initial New York base, the online broker told *Matters*. *Matters* exclusively reported BidURenergy's electric broker license applications in Pennsylvania and Illinois in the past week (Only in Matters, 12/29/09 and 1/5/10).

Aside from the four states cited, Connecticut and the Indiana gas market are also high on BidURenergy's expansion plans, as the online broker eventually plans to offer service in every competitive electric and gas market in the U.S.

BidURenergy also said yesterday that 10 suppliers are now offering service on its site. As only reported in *Matters*, Energetix, Gateway Energy Services, and Hudson Energy Services are among the suppliers offering residential service. Glacial Energy and NYSEG Solutions are among the suppliers that have been identified as offering non-residential service on the site; BidURenergy could not disclose additional suppliers due to confidentiality provisions. Corey Akios, Coordinating Director of BidURenergy, did report that three of the recently added suppliers are national retailers which typically offer residential service.

BidURenergy also said that it has started to open its platform to other aggregators or brokers that typically bid their clients out to several suppliers. Those brokers can generally realize margins similar to what they would otherwise realize for administering the entire bid process themselves, BidURenergy said. BidURenergy said that it has brought more than 20 brokers to its platform.

In its new markets, BidURenergy will employ a similar marketing strategy to its approach used in New York, which has emphasized a mass marketing push (see Matters, 8/25/09). Direct mailings will be used in its new markets, as will mass advertisements.

Duke Energy Ohio Opposes Recommendation to Analyze Imbalances

Duke Energy Ohio opposes a recommendation from the Northstar Consulting Group to analyze market impacts as a result of annual marketer imbalances because the issue does not appear to be critical and would amount to an unnecessary diversion of resources.

Duke was responding to recommendations from the Northstar Consulting Group in a management/performance audit of Duke's gas purchase practices and policies.

Northstar had said that Duke's methodology to split daily nominations between GCR and Choice customers is not achieving reliable results. "Day-to-day nominations by the independent marketers result in monthly totals that vary greatly from actual supply requirements," Northstar said.

However, Northstar goes on to say that, on an annual basis, "the total amount of natural gas to balance is negligible." In 2007, the amount represented 0.8 percent of the total deliveries to the Choice customers, followed by 2.3 percent in 2008 and 4.4 percent in 2009. On a system wide basis, where Choice deliveries are approximately 25 percent, the differences are reduced by a factor of four.

Still, Northstar noted that, individually, imbalances among 16 suppliers on Duke's system can vary "drastically" as one marketer may end up, at the end of the year, owing Duke gas while another marketer may finish the year being paid for gas by Duke. Northstar noted one unnamed marketer recorded a negative 61% annual imbalance, while two others recorded imbalances of 12% and 10%.

"This results in DE-Ohio serving as both a finance company and a natural gas bank to all of the marketers instead of simply serving the role of determining appropriate nominations and scheduling. In its finance and bank roles, there is no interest or time value of money or commodity," Northstar noted.

Northstar cited three factors as contributing to imbalances:

- The Gas Firm Equations have not been updated since 2003
- The changes in the seasons result in seasonal billing carryover
- New customers are assigned an actual to average customer ratio of 1.0. The ratio was traditionally updated every October

However, aside from stressing, as Northstar concedes, that the imbalance is ultimately negligible, Duke noted that those individual marketers with high percentage imbalances have relatively small pools. The marketer with the 61% imbalance serves a total of 6 commercial/industrial customers, Duke noted.

While Duke does not believe an analysis of imbalances is warranted, Duke agreed to monitor annual imbalances starting in June 2010 using its Transportation Management System.

BP Energy Seeks Clarification on Use of Permanent Capacity Release by AMAs

BP Energy Company requested that FERC clarify that an asset management arrangement (AMA) capacity release can include a permanent capacity release as long as the release meets all of the requirements of an AMA release as set forth in 18 C.F.R. § 284.8(h)(3).

BP Energy's request came in response to a December 10, 2009, FERC order, in which the Commission accepted the permanent capacity release negotiated rate agreement between Gulf Crossing Pipeline Company and JP Morgan Ventures Energy Corporation, but did not specifically recognize the AMA nature of the capacity release (RP10-184).

The permanent capacity release at issue is part of an AMA transaction between Antero

Resources Corporation and JP Morgan, with JP Morgan required to purchase and Antero required to deliver 20,000 MMBtu/day or 100% of the released agreement's daily Maximum Daily Quantity (MDQ) on a daily basis for the remaining term of the released agreement. In posting the capacity release transaction on its electronic bulletin board, Gulf Crossing noted that the transaction is a permanent release of a negotiated rate firm transportation agreement, pursuant to the asset management arrangement and in accordance with Order 712, but the FERC order did not recognize the nature of the transaction.

"Because neither the Commission's December 10, 2009 order in this proceeding nor Gulf Crossing's November 25, 2009 filing recognize that the subject permanent capacity release is an AMA capacity release, BP requests that the Commission clarify that permanent capacity releases can qualify as AMA capacity releases," BP said. Specifically, BP requested that the Commission confirm that an asset manager and its asset management customer may enter into a permanent capacity release that qualifies as "a release to an asset manager" under 18 C.F.R. § 284.8(h)(3), and that such releases are exempt from the Commission's bidding requirements, the pipeline's bidding requirements, and the Commission's tying prohibition, as long as the release satisfies the conditions set forth in the Commission's regulations.

BP noted that no provision of Order No. 712, Order No. 712-A or Order No. 712-B contains any limitation, qualification or condition stating expressly that a qualified AMA cannot involve a permanent capacity release. "Limiting the availability of a regulatory exemption to circumstances and conditions not stated in a written final rule would constitute an absence of reasoned decision-making," BP said.

PacifiCorp Asks FERC to End Use of Market Monitor

PacifiCorp petitioned FERC for approval, if necessary, to remove the Market Monitor that PacifiCorp instituted upon MidAmerican Energy Holdings Company's acquisition of PacifiCorp in 2005, arguing that a monitor is no longer required due to changed circumstances (EC05-110).

PacifiCorp noted that the Monitor was voluntarily proposed by PacifiCorp in the acquisition proceeding, and FERC did not condition its approval of the transaction on the monitoring plan. Thus, PacifiCorp argued that it's unclear if FERC approval to cease use of the Monitor is even required.

PacifiCorp said that MidAmerican Energy Company's integration into the Midwest ISO effective September 1, 2009 obviates the need for the Monitor as MidAmerican Energy Company is now subject to the MISO market monitoring plan, and the Monitor no longer reports on the MidAmerican Energy Company assets which are in a different interconnect.

Furthermore, PacifiCorp argued that its Order No. 890-compliant open access transmission tariff will continue to mitigate any vertical market power stemming from PacifiCorp's ownership and operation of transmission facilities, while joint planning initiatives and significant planned transmission expansion, "provide additional safeguards to ensure pro-competitive, transparent and not unduly discriminatory operation of PacifiCorp's transmission system." PacifiCorp noted that the Monitor did not once observe any anti-competitive behavior since the 2006 acquisition.

"Continued market monitoring is no longer necessary in light of these developments. Continued reliance on the Market Monitor will cost the company and its ratepayers funds that can be better spent ensuring competition and non-discriminatory access to PacifiCorp's transmission system through OATT and other compliance efforts, as well as expansion of transmission facilities," PacifiCorp said. Granting the petition would save PacifiCorp ratepayers at least $168,000 per year, PacifiCorp said.

Briefly:

Verde Energy USA Seeks Pa. Electric License

Connecticut start-up electric supplier Verde Energy USA filed for a Pennsylvania electric supply license as a broker/marketer serving all customer classes in all service areas, part of a previously reported expansion to other markets once it began flowing to customers in Connecticut (Only in Matters, 8/13/09). As noted yesterday, December represented the first month Verde served Connecticut customers, with 84 flowing customers at United Illuminating as of December 31. Verde's standard mass market contract for Pennsylvania would be a monthly variable product. Verde will use EC Infosystems for EDI, billing and backoffice functions, and Customized Energy Solutions for procurement support and supply management.

Hess Files for Pa. Conservation Service Provider License

Hess Corporation submitted an application for licensure as a Pennsylvania conservation service provider. Hess said that it offers customers demand response services, and can design and manage various energy efficiency and conservation services for electric distribution companies.

UGI Central Penn Seeks Waiver of Md. COMAR 20.59

UGI Central Penn Gas Inc. asked the Maryland PSC for a waiver from the requirements of COMAR 20.59, regulations for competitive gas supply, which, among other things, require LDCs to either institute purchase of receivables or proration of partial payments between supply and delivery charges. UGI Central Penn's territory includes part of Frederick County, Md., where it has approximately 420 residential and 70 commercial sales service customers. UGI Central Penn said that COMAR 20.59 does not apply to it because it does not offer a gas choice program, and COMAR 20.59 is applicable to, "gas utilities and suppliers only in service territories where customers may elect retail gas supply or gas supply services."

Energy Future Holdings to Issue $300 Million in Debt

Energy Future Holdings Corp. announced yesterday that it intends to commence a private offering of $300 million principal amount of senior secured notes due 2020. EFH intends to use the net proceeds from the offering for general or other corporate purposes, which may include, without limitation, working capital needs, investment in business initiatives, capital expenditures, and prepayment or repurchase of outstanding indebtedness of EFH and/or its subsidiaries.

DNPs ... *from 1*

low temperatures.

Citing the National Weather Service severe winter weather advisory and hard freeze watch, Texas-New Mexico Power is suspending execution of Disconnect for Non-Pay transactions for January 7th in all of its service territories due to safety concerns. Assuming no further weather advisories are issued, TNMP will resume execution of DNPs on January 11th. Transactions scheduled for January 7th will be cancelled and REPs may submit new DNP requests for dates starting January 11th.

Calif. ... *from 1*

phase-in, as this approach would ensure that any unused portion of the cap would automatically roll into the next year. This proposal is in contrast with Pacific Gas & Electric's recommended phase-in process, which would open an additional, flat amount of kilowatt-hours per year with no carry-over to the next.

Southern California Edison also favored a three-year phase-in, but using a slower schedule. SCE proposed allocating 34% of the available room under the cap in year 1, an additional 33% in year 2, and the final 33% in year 3. "Allowing for significantly more DA enrollment in year 1 could have a detrimental impact on implementation, and an equal allotment of the available DA load over the phase-in period mitigates this concern," SCE said. SCE supports rolling over unused kilowatt-hours into the next year, however.

TURN initially suggested a four-year phase-in schedule, though it is amendable to a three-year schedule with some front-loading if such a process does not pose problems for utilities. San Diego Gas & Electric is generally amenable to a three-year phase-in schedule.

CACES, AReM, SCE and SDG&E all support a one-time waiver of the six-month notice requirement and three-year minimum stay

Eligible Direct Access Load Versus Available Space Under Cap (GWh/yr)

	SCE	PG&E	SDG&E
Cap	11,710	9,521	3,562
Baseline	7,627	5,574	3,100
New DA Load	4,083	3,947	462
Three year stay information – load			
Expiring load by year end 2010	3,202	2,293	210
Expiring load by year end 2011	63	475	9
Expiring load by year end 2012	252	216	9
Expiring load by year end 2013	16	25	23
Total	3,533	3,009	251
Expiring load as a % of new DA load	87%	76%	54%

requirement, and TURN also said that one-time waivers may be appropriate.

None of these five parties supported preferential treatment for existing direct access-eligible load, as AReM and CACES noted that currently direct access-eligible load serving a minimum stay on bundled service equals 87% of the current space available under the cap at SCE, 76% at PG&E, and 54% at SDG&E (see chart above).

AReM and CACES only listed non-residential load currently on a minimum stay, so the total amount of direct access-eligible load which could fill space under the cap is slightly higher, from residential customers retaining their right to direct access by shopping when direct access was suspended (see chart in 12/8/09 issue). AReM and CACES also labeled the minimum stay end date differently than the utilities, as load in the AReM/CACES first category, expiring load by year-end 2010, will actually all be expired by April 2010, and the next row expires by April 2011 (rather than year-end 2011), and so forth. Of note is that the vast majority of currently eligible load on a minimum stay will roll off the minimum stay in April 2010, at which point, presuming they fulfilled their notice requirement, customers could immediately enroll onto direct access (perhaps even submitting their enrollment ahead of time for an April flow), versus the lag which will exist between the time the PUC approves a final phase-in process and newly eligible direct access customers would be ready to flow.

While most parties favored a first come, first served priority under the cap, AReM and CACES offered a slightly different process that would operate on a first come, first served basis at a high level, but bundle customers whose switch requests are submitted on the same day as being the same vintage (rather than prioritizing switch requests using a timestamp, and then using the timestamp to determine the final eligible switch when the cap is met). Under the AReM/CACES approach, when a batch of switch requests would exceed the direct access limit, the utility will determine the percentage of the total MWh load contributed by each supplier who submitted a switch in that batch, and how much load can be accommodated under the cap. Based on the available space, the utility would then calculate a reduction to the amount of load that can be submitted by each supplier, in proportion to the total amount of load associated with the switches that the supplier has submitted. Within 24 hours of being notified of its pro-rata reduction, the supplier would determine which switches should go forward under its reduced allocation, and submit a new list of such switches to the utility.

CACES and AReM also urged the Commission to verify that the load cap data listed by the utilities is correct, as stakeholders cannot publicly verify the data. However, AReM and CACES did note some inconsistencies in the level of current direct access load at the utilities in various public reports, which is likely due to the timing of the data as well as the annualization calculation used. Still, CACES and AReM asked that the utilities confirm that such inconsistencies are explained by those factors (see chart next page).

Current Baseline Direct Access Participation, By Report (GWh/yr)

	SCE	PG&E	SDG&E
Baseline data (per 12/29/09 filings)	7,627	5,574	3,100
Baseline data per ERRA filings	7,688	5,890	3,242
Difference	61	316	142
% Difference	1%	5%	4%
Baseline data per CEC report	7,699	5,483	3,175
Difference	72	-91	75
% Difference	1%	-2%	2%

SCE and SDG&E both support a waiver of the requirement for direct access customers above 50 kW to install an interval meter, a waiver which PG&E opposes.

TURN raised a "potentially serious problem" requiring immediate attention regarding local resource adequacy. If the direct access market reopens on April 11, 2010, a customer's new supplier will not - at least under current rules -- be required to obtain its proportionate share of local resource adequacy resources until the 2011 resource adequacy compliance year, because local resource adequacy is subject to only an annual compliance obligation, with no monthly true-up. At the same time, the utility that loses the load will have no market for the local resource adequacy resources that it had previously procured to serve that load. "As a result, bundled service customers may be left with a disproportionate share of Local RA obligations and costs for the remainder of 2010, including the critical summer peak period when RA is particularly valuable and costly," TURN said.

As an interim solution, TURN proposed that electric service providers serving additional load as a result of the direct access re-opening be required to purchase the proportional amount of local resource adequacy capacity from the host utility at the resource adequacy "waiver trigger" price of $40 per kW-year, pro-rated as appropriate for the remainder of the current year. "This will help to prevent inappropriate gaming and avoid creating a perverse incentive for customers to switch providers simply to avoid their fair share of Local RA costs," TURN said.

SCE argued that the equity provisions in SB 695 require the Commission to address the current "inequities" in RPS requirements, as SCE noted that, unlike utilities, competitive suppliers are not required to conduct RPS solicitations, comply with least-cost, best-fit criteria, submit their RPS contracts to the Commission for approval, or offer 10-, 15- and 20-year contracts in their RPS solicitations.