CHARGE Conference Call

June 23, 2011 – 9:30 a.m.

Call-in number: 1-866-618-6746 and Access Code: 6060145

Recap of Discussion

17. <u>EGS Marketing Activities</u>

- PUC adopted guidelines on November 4, 2010, which is available at the following link: http://www.puc.state.pa.us/general/ConsolidatedCaseView.aspx?Docket=M-2010-2185981

- Proposed rulemaking order adopted by PUC at February 10, 2011 Public Meeting; copy of entered order is attached; can be accessed on OCMO page and at the following link: http://www.puc.state.pa.us/general/ConsolidatedCaseView.aspx?Docket=L-2010-2208332

  - Comments will be due 60 days after publication in Pa. Bulletin; publication has not yet occurred due to questions from the Office of Attorney General; staff will advise the group when the proposed regulations are published

30. <u>Estimated State Tax Amount on Bills</u>

- Question has arisen about whether the presentation of "estimated total state taxes" on residential bills is required for generation charges of EGS as there is no standard treatment among EGSs; more recently, EDEWG asked CHARGE to resolve issue so that requirement for tax field on EDI 810 Bill Ready Invoice can be eliminated

  - Components of EDC's "estimated total state taxes" components are Capital Stock, Property Tax-Local and PURTA, State Unemployment Compensation, PA State Income Tax, and Gross Receipts Tax

  - Resolution of this issue will not affect presentation of GRT by EGSs

  - Staff is reviewing statute and regulations to offer guidance to EGSs on issue of whether their state taxes (other than GRT) must be displayed

- EGSs are either not populating the state tax field or are populating it with zero; EGS prices are computed using different methods, raising questions about whether requirement is practical; no party expressed desire to require EGSs to show "estimated total state taxes"

- Secretarial Letter will be forthcoming; Staff shared guidance as follows:

  - EGS-GRT needs to be included on bill, but since we are aware that some EDCs cannot accommodate that, PUC will temporarily waive requirement and ask OCMO/CHARGE to explore what has to be done to have this information included
  - EGS-PA State Sales Tax needs to be included on bill, if applicable
  - EGS-Other State Taxes do not need to be included on bill; if EGS is performing Supplier Consolidated Billing, EGS will need to include EDC-Other State Taxes

31. <u>Eligible Customer List</u>

- PUC adopted final order on November 12, 2010, which is available at the following link: http://www.puc.state.pa.us/general/ConsolidatedCaseView.aspx?Docket=M-2010-2183412
- OCA and PA Coalition Against Domestic Violence filed Petitions for Review with Commonwealth Court, which has granted stay of November 12, 2010 order
- Commission issued Secretarial Letter on February 15, 2011 clarifying effect of stay and filed an Application for Remand with Commonwealth Court, which was granted
- Commission entered attached Reconsideration Order for comment on June 13, 2011; comments are due on July 13, 2011 and reply comments are due on July 28, 2011

44. <u>Net Metering Customers/EDI Change Control #85</u>

- Questions have been raised by customers who have net metering arrangements with EDCs and then switched to EGSs without entering into net metering contracts with the EGSs; staff noted the need for customers to make these arrangements with EGSs before they switch
  - Staff has encouraged EDCs to educate customers at the time they sign a net metering contract and during the enrollment process (i.e. confirmation letter)
  - Staff has encouraged EGSs to also ensure that customers are aware before they switch that if they are on a net metering tariff, they will no longer receive energy credits from the EDC; it is up to EGSs if they want to offer energy credits to the customer
- EDEWG Update: EDI Control Change #85 would add special meter configuration segment to the EDI 814 Enrollment, Change, Reinstatement and EDI 867 Historical Usage and Historical Interval Usage transaction sets
  - Consensus not achieved in EDEWG; issue referred to CHARGE (summary attached)
  - EGSs are supportive of change; EDCs generally do not object to change but point to time and resources needed to implement; Duquesne plans to automate process in

the first quarter of 2013; Duquesne and PPL currently send spreadsheets to EGSs with this information

- Discussion of any EDC plans to include this information on ECL
    - PPL plans to include it after the first of the year (2012); Duquesne has submitted request to compliance team; First Energy does not have confirmation of moving forward but does not anticipate problems; and PECO has submitted a request to team to include net metering indicator on ECL
- Staff will consult internally and offer a proposal for moving forward for discussion during a future call

45. <u>Accelerating Supplier Switching Timeframes</u>

- Group discussed enrollment process/supplier switching timeframes
- As outlined in the attachment (revised to include points from today's discussion), the process currently takes 16-45 days
    - Includes the 10-day confirmation period required by the PUC's anti-slamming regulations
    - No mid-cycle switches are done, so that if the enrollment is not submitted at least 16 days prior to the next meter read, the switch is delayed to the next meter read 30 days later
- Staff has done outreach with EDCs and other states, including Texas and Maryland; it was suggested that Connecticut's process also be reviewed
    - Staff suggested that EGSs should be mindful of customers' meter read dates and strive to send enrollments at least 16 days prior to those dates, and communicate the timeframes for switching to customers
    - Staff also asked for feedback on reducing the 10-day confirmation period and on the possibility of mid-cycle switches
- EGSs expressed support for changes that would accelerate the switching timeframe
    - Waiting period could be eliminated, with economic penalties for slamming that would result in customers being held harmless
    - Confirmation process could be electronic
    - Smart meters should make it technically feasible to do mid-cycle switches

- EDCs expressed concerns about changes that would accelerate the switching timeframes
    - Easier to unwind slamming prior to the customer being switched
    - Billing systems are built around meter read dates and would need expensive IT changes
    - PJM settlement process may not support mid-cycle switches
- OCA agrees with looking for a cost-effective mechanism to accelerate the switching process but views the confirmation letter as a key to maintaining credibility of the process; would be open to discussing a shorter confirmation period
- Staff appreciates the input and will continue discussing the issue and gathering more information as necessary to report back to the Commissioners
- Staff noted that a comprehensive report with recommendations is nearly finalized for distribution to the Commissioners offices; staff hopes to have a tentative order issued for comment later this summer (maybe in August)

46. <u>Statewide Investigation</u>

- PUC has launched statewide investigation to ensure properly functioning and workable competitive retail electricity market exists in the Commonwealth; Docket No. I-2011-2237952
- Information posted on website at: http://www.puc.state.pa.us/electric/Retail_Electricity_Market.aspx
- Investigation will examine both the legislative and regulatory framework behind Pennsylvania's retail market, including an analysis of the current default service model and whether, as currently structured, that model is hindering competition
- Order entered on April 29, 2011; Comments due June 3, 2011; En Banc Hearing on June 8, 2011 at 1:00 p.m.
- To be added to distribution list, please send email to ra-RMI@state.pa.us
- Staff reported on next steps; expect issuance of a Commission order at either July 14 or 28 Public Meeting outlining the issues that should be addressed by stakeholders during investigation; and anticipate formation of subgroups to develop proposals that will culminate in work product going to the Commission by April 2012

47. **Price to Compare on Bill**

- Question has arisen about whether it would be appropriate (not required) for EDC to include price to compare on bill; all EDCs are currently providing price to compare on bills except for PPL who is planning to move forward to also include
- Prior feedback on this concept, including accuracy, effect on competition and value to consumers
    - It was noted that if this information is included, it is important to state that it is valid for a period of time and subject to change
    - It was also suggested that perhaps it should be included only for residential and small commercial customers
    - Some concerns were raised about the possibility of further confusing customers especially with quarterly price adjustments and that including the PTC may suggest that price is the only relevant factor
- Staff has reviewed MD order, which is attached, and noted some key points:
    - Price to Compare term was discarded
    - All bills must include current price, future price and the date after which prices are unknown
    - Utilities must also provide this information on their websites
- Discussion of MD model will be held during July 21 CHARGE call

48. **PPL Billing System Issues**

- PPL is experiencing some billing system issues
    - Unmetered accounts-EGSs have been charged with energy but not recovered costs; PPL has sent lists to affected EGSs and has committed to paying EGSs
    - Finalized accounts-EGSs receiving rejections due to usage charges being received outside the bill window even when they are timely submitted; PPL cannot bill these customers and has told EGSs to send bills
    - Rejection of 867 usage transactions without notice to EGSs; PPL's system is automatically rejecting due to exceeding bill tolerances; text on customers' bills indicates that PPL did not get the charges from the EGS on time
- Status report from PPL on addressing these issues

    - Unmetered accounts-PPL has made adjustments so that all affected EGSs have recovered costs

    - Finalized accounts-Problem is fixed going forward, but some residual accounts that were affected prior to the fix are still being worked; expect to complete that process within the next couple of weeks

    - Rejection of 867 usage transactions without notice to EGSs-Fix is in progress and should be done within the next couple of weeks

  - PPL encouraged EGSs to use the supplier hotline or email address to report any problems

49. <u>Unit Pricing and State Sales Taxes on Bills</u>

- Secretarial Letter issued on May 27, 2011 reminding EGSs that unit pricing must be included on bills for residential and small business customers' bills and alerting EGSs to the improper inclusion of state sales taxes on some residential customers' bills

- Staff appreciates the responses received from EGSs regarding compliance with these matters and is following up with those who did not respond

50. <u>Labels of Charges on Bills</u>

- Question has arisen about the labels that must be used to describe charges on bills for residential and small business customers; see 52 Pa. Code §54.4(b)(3), which requires labels of generation and transmission charges; issue was also discussed in March 1999 Staff letter, which is attached

- Many EGSs are using "Energy" charges; some EDCs do not have sufficient space to include "Generation and Transmission" in the EDI transaction

- Staff is concerned about customer confusion if the bills say "Energy" charges but all other materials (marketing, disclosure statements, etc) say "Generation and Transmission"; however, we are not aware of any consumer complaints about the issue

- PPL will look at issue to determine whether capability depends on bill ready vs . rate ready; it appears that the issue may resolve itself as EDCs add space to permit the inclusion of "Generation and Transmission"

51. <u>Peak Load Contribution & Network Service Peak Load Values/EDI Change Control #87</u>

- Add effective date of Peak Load Contribution & Network Service Peak Load values to the EDI 867 Historical Usage and Historical Interval Usage transaction sets

- EDEWG has been unable to reach consensus and is referring to CHARGE for resolution

- Change would enable EDCs to report effective dates for both current and future PLC/NSPL values; currently the non-incumbent EGS cannot receive the future values via EDI until after June 1 when it becomes current

- EGSs are supportive of change and indicate need for future values in pricing products; EDCs generally do not object to change but point to time and resources needed to implement; FirstEnergy plans to include future values on ECL; Duquesne emails future values to EGSs; PECO posts an ECL list with future values

- Staff will consult internally and bring a proposal back for discussion during a future CHARGE call

General Matters

A. New Issues

- Any new issues or questions about issues previously discussed on CHARGE calls should be submitted to ra-ocmo@state.pa.us

B. Old Agendas/Recaps

- All agendas and recaps are posted on the OCMO page of the website along with various other documents that have been distributed or relied upon during CHARGE discussions, at the following link - http://www.puc.state.pa.us/electric/electric_CompetitiveMarketOversight.aspx

C. CHARGE Distribution List

- To be added to the CHARGE distribution list, please send an email to ra-ocmo@state.pa.us

D. CHARGE Contact List

- Contact list is on website at the following link:

  http://www.puc.state.pa.us/electric/electric_CompetitiveMarketOversight.aspx

- Please send contact information or updates to ra-ocmo@state.pa.us; purpose of this list is to enable stakeholders to contact one another directly to resolve issues and is separate from email distribution list

E. Meeting Schedule for 2011

- July 21, 2011, 9:30 a.m.
- August 18, 2011, 9:30 a.m.
- September 15, 2011, 9:30 a.m.
- October 20, 2011, 9:30 a.m.
- November 17, 2011, 9:30 a.m.
- December 22, 2011, 9:30 a.m.

June 15, 2011

Dear OCMO / CHARGE Staff,

CHARGE has been discussing agenda item #44 – Net Metering Customers for the past few meetings. During the June 2nd, 2011 EDEWG meeting, the group was unable to reach consensus on approving EDI Change Control #85 (p. 2-7 below). EDI Change Control #85 was submitted by Sue Scheetz (PPL Electric Utilities) to add a special meter configuration segment to the EDI 814 Enrollment, Change, Reinstatement and EDI 867 Historical Usage and Historical Interval Usage transaction sets. This would require the EDCs to notify the EGS if customer generation is present on a given account both pre and post enrollment. EDEWG leadership met separately and agreed EDI Change Control #85 should apply to all EDCs in Pennsylvania thus making the change mandatory.

No EGS has oppossed this EDI Change Control, in fact many believe this information is very vital in supporting customers with their own form of generation. Today, both Duquesne Light and UGI omit passing the customer generation qualifiers in their EDI 867 Monthly Usage transactions, currently the only way an EGS knows a net meter is present. Often times, there will be usage variances due to customer generation which requires the EGS to contact these EDCs directly because the EGS has nothing electronically stating the customer is net metered. The statewide implementation of EDI Change Control #085 will provide EGSs the ability to know prior to and during enrollment, customer generation is present on an account. It will also provide the ability for the EDC to inform the EGS the in the event an existing customer installs their own generation after enrolling with an EGS.

The EDCs each reported their positions regarding EDI Change Control #85 as follows…

West Penn Power	Unable to implement due to merger/code freeze, should address under First Energy system as WPP is migrating to FE's SAP system.
First Energy	Currently a manual process to identify net meter accounts. Legal dept. looking into net metering rules when customer elects an EGS.
Duquesne Light Company	Currently unable to identify within billing system, customer generation accounts are manually supported by DLC staff.
UGI Utilities	Same as DLC, unable to identify, manually supported by UGI staff.
PPL Electric Utilities	Supports change, currently a manual process but moving to automated support, which will eliminate PPL's manual efforts.
PECO	Will not support without cost recovery mechanism.

EDEWG requests CHARGE add EDI Change Control #85 to agenda item #44. EDEWG also requests that CHARGE attempt to obtain statewide approval of EDI Change Control #85 for EDC implementation with a documented timeline for each EDC. In the event CHARGE is unable to do so, EDEWG requests CHARGE make a formal recommendation and escalate EDI Change Control #085 to the Commission for a final decsion.

Sincerely,
/s/ Brandon S. Siegel
EDEWG EDI Change Control Manager

EDEWG Change Request #085

This EDEWG Change Request can be found on the PUC website at
http://www.puc.state.pa.us/electric/electric_edewg_download.aspx

Requester's Name: Susan Scheetz	**EDC/EGS Name**: PPL Electric Utilities	**Phone #** : 610-774-3616
Date of Request: 3/3/2011	**Affected EDI Transaction Set #(s)**: 814E, 814C, 814R, 867HU, 867HIU	**E-Mail Address**: smscheetz@pplweb.com
Requested Priority (emergency/high/low): Low	**Requested Implementation Date**: TBD	**Status**: Open; non-consensus – escalated to PUC Staff / CHARGE

Brief Explanation (This will be copied into the description in the Change Control Summary Spreadsheet):

This change control adds a new segment to 814E/C/R & 867HU/HIU to inform the EGS a net meter is present, added, or removed from an LDC account. Also adds net metering/reverse flow quantity codes in the 867HU/HIU.

Detail Explanation (Exactly what change is required? To which EDEWG Standards? Why?):

1. 814 Enrollment, Change and Reinstatement - Add new REF*KY segment to the LIN Loop to indicate Special Meter Configuration exists on the account. REF02 codes from PPLEU have been suggested as follows…(The A is for Act129 metering, and the N is for non-act 129.)

Value	Description
ASUN	Net Metering Solar
AWIN	Net Metering Wind
AHYD	Net Metering Hydro
ABIO	Net Metering Biomass
AWST	Net Metering Waste
ACHP	Net Metering Combined Heat and Power
AMLT	Net Metering Multiple Different Sources
NSUN	Non-Net Metering Solar
NWIN	Non-Net Metering Wind
NHYD	Non-Net Metering Hydro
NBIO	Non-Net Metering Biomass
NWST	Non-Net Metering Waste
NCHP	Non-Net Metering Combined Heat and Power
NFOS	Non-Net Metering Fossil Fuel
NMLT	Non-Net Metering Multiple Different Sources

2. 814 Change - And new REFKY code to the Reason for Change (REF*TD) segment and use the existing REF*03 to indicate Add or Delete of the Special Meter Configuration.

3. 867 Historical Usage & 867 Historical Interval Usage - Add QTY01 values 87 = Actual Quantity Received for net metering and 9H = Estimated Quantity Received for net metering to PTD Loops SU, RT and PM.

4. 867 Historical Usage & 867 Historical Interval - Add new REF*KY segment to the PTD*FG Loop to indicate Special Meter Configuration exists on the account. REF02 codes will be determined at a future date.

The addition of this segment will also provide future capability to denote other special meter configurations such as electric vehicle, Type B, Multi-Feed, etc. The EDEWG leadership met on 4/25 and agreed this change would be required by all EDCs in PA.

For Change Control Manager Use Only:

Date of EDEWG Discussion: 4/7/11, 5/12/11, 6/2/11	Expected Implementation Date: TBD	

EDEWG Discussion and Resolution:

3/9/2011-Received change request, entered into tracking, assigned #085, and placed on agenda for 4/7/11 EDEWG meeting.

4/7/2011-EDEWG reviewed and discussed CC85. PPLEU would like to adopt the concept of this change ASAP so immediate coding may begin to support the REFKY in the 867HU/HIU transaction sets. EDEWG leadership will meet to determine potential REF02 codes for net metering/reverse flow metering support. EDI CC85 remains open pending further EDEWG review.

5/12/2011-EDEWG discussed CC85. Leadership met on 4/25 to confirm this change is required by all EDCs to implement. EDEWG requested the EDCs review and report back with implementation timelines during the June meeting. CC85 remains open pending further review.

5/18/2011-PPLEU provided initial list of REF02 codes, see p3

6/2/2011-EDEWG reviewed EDI Change Control #85. Suppliers believe this change will improve the handling of accounts with customer generation by information the EGS there is some form of customer generation present on the account which is currently unavailable on either the ECL or in the existing EDI transaction sets. The EDC's position regarding EDI CC 85 is as follows:
WPP: under a code freeze due the FE merger, needs addressed under FE's system.
FE: currently a manual process to identify these accounts, legal dept. assessing customer generation rules.
DLC: currently system unable to identify, customer generation accounts are manually supported.
UGI: Same as DLC, unable to identify, manually supported.
PPLEU: supports change, currently a manual process but moving to automated support, eliminating manual efforts.
PECO: will not support EDI CC85 without cost recovery.

Due to PECO's non-support and other EDC's manual processes, EDEWG is unable to reach consensus on EDI Change Control 85. The EDI Change Control will be escalated to CHARGE for resolution by the EDI Change Control Manager.

6/15/11 – EDI Change Control Manager escalated to CHARGE/PUC Staff. EDI CC 85 remains open.

Priority Classifications

Emergency Priority	*Implemented within 10 days or otherwise directed by EDEWG*
High Priority	*Changes / Enhancements implemented with 30 days. The next release, or as otherwise directed by EDEWG*
Low Priority	*Changes / Enhancements implemented no earlier than 90 days, Future Release, or as otherwise directed by EDEWG*

Please submit this form via e-mail to both the PUC at annmarino@state.pa.us ***and to the Change Control Manager, Brandon Siegel at*** bsiegel@ista-na.com

Your request will be evaluated and prioritized at an upcoming EDEWG meeting or conference call.

1. 814 Enrollment, Change and Reinstatement – LIN Loop

Segment:	**REF Reference Identification (KY=Special Meter Configuration)**
Position:	030
Loop:	LIN
Level:	Detail
Usage:	Optional
Max Use:	>1
Purpose:	To specify identifying information
Syntax Notes:	**1** At least one of REF02 or REF03 is required.
	2 If either C04003 or C04004 is present, then the other is required.
	3 If either C04005 or C04006 is present, then the other is required.
Semantic Notes:	**1** REF04 contains data relating to the value cited in REF02.
Comments:	
PA Use:	Required when special meter configuration is present on an account
NJ Use:	Not Used
DE Use:	Not Used
MD Use:	Not Used
Example:	REF*KY* NMSUN000000000

Data Element Summary

	Ref. Des.	Data Element	Name	X12 Attributes	
Must Use	**REF01**	**128**	**Reference Identification Qualifier**	**M**	**ID 2/3**
			Code qualifying the Reference Identification		
			KY — Site Specific Procedures, Terms, and Conditions Special Meter Configuration		
Must Use	**REF02**	**127**	**Reference Identification**	**X**	**AN 1/30**
			Reference information as defined for a particular Transaction Set or as specified by the Reference Identification Qualifier		

Code	Description
ASUN	Net Metering Solar
AWIN	Net Metering Wind
AHYD	Net Metering Hydro
ABIO	Net Metering Biomass
AWST	Net Metering Waste
ACHP	Net Metering Combined Heat and Power
AMLT	Net Metering Multiple Different Sources
NSUN	Non-Net Metering Solar
NWIN	Non-Net Metering Wind
NHYD	Non-Net Metering Hydro
NBIO	Non-Net Metering Biomass
NWST	Non-Net Metering Waste
NCHP	Non-Net Metering Combined Heat and Power
NFOS	Non-Net Metering Fossil Fuel
NMLT	Non-Net Metering Multiple Different Sources

2. 814 Change

Segment:	**REF Reference Identification (TD=Reason for Change)**
Position:	030
Loop:	LIN
Level:	Detail
Usage:	Optional
Max Use:	>1
Purpose:	To specify identifying information
Syntax Notes:	**1** At least one of REF02 or REF03 is required. **2** If either C04003 or C04004 is present, then the other is required. **3** If either C04005 or C04006 is present, then the other is required.
Semantic Notes:	**1** REF04 contains data relating to the value cited in REF02.
Comments:	
Notes:	This convention of the REF segment is used for account maintenance, to convey change reason codes. The codes used in REF02 are maintained by the UIG. The first portion of the code identifies the segment that contains the data that has been changed; the remaining portion of the code identifies the relevant code qualifier for the data that has been changed. The changed data will appear in the appropriate element of the identified segment. For example, a REF02 code of AMT7N indicates that data in the AMT segment that is identified by the qualifier 7N (i.e., Percentage of Service Supplied) has been changed to the value now shown in AMT02.
PA Use:	Request: Required if change is at an account (LIN) or header level Response: Optional
NJ Use:	Same as PA
DE Use:	Same as PA
MD Use:	Same as PA
Example:	REF*TD*REFBLT REF*TD*N1PK*D REF*TD*REFKY*A

Data Element Summary

	Ref. Des.	Data Element	Name	Attributes
Must Use	REF01	128	**Reference Identification Qualifier** Code qualifying the Reference Identification TD — Reason for Change	M ID 2/3
Must Use	REF02	127	**Reference Identification** Reference information as defined for a particular Transaction Set or as specified by the Reference Identification Qualifier	X AN 1/30

AMT5J	Change Number of Load Management Air Conditioners
AMT7N	Change Percentage of Service Supplied
AMTDP	Change Percentage of Service Tax Exempt
AMTF7	Change Percentage of State Sales Tax
AMTKC	Change Peak Load Capacity
AMTKZ	Change Network Service Peak Load
AMTL0	Change Number of Load Management Water Heaters
AMTQY	Change Eligible Load Percentage
AMTRJ	Change of ESP Rate Amount
DTM150	Change Service Period Start Date
DTM151	Change Service Period End Date
N12C	Change in party to receive copy of bills
N18R	Change in Customer Name and/or Service Address
N1BT	Change in Billing Address
N1PK	Change in party to receive copy of notices (not bills)

			REF11	Change ESP-Assigned Account Number for the End Use Customer		
			REF12	Change LDC-Assigned Account Number for the End Use Customer		
			REF17	Change of Interval Status Change in Interval status will have a LIN05 value of SI.		
			REFBF	Change Billing Cycle		
			REFBLT	Change Billing Type (Bill Presenter)		
			REFKY	Change Special Meter Configuration		
			REFPC	Change Party that Calculates the Bill		
			REFSPL	Change Point at Which the Customer is Connected to Transmission Grid Change in PJM LMP Bus		
Conditional	**REF03**	**352**	**Description**		**X**	**AN 1/80**
			A	Indicates the data element to be added Optional ~~when adding additional address~~ • Party to Receive copy of notices (Not bills) –N1PK • Special Meter Configuration (net meter added)		
			D	Indicates the data element to be deleted Required if deleting the following address types: • Party to Receive copy of bills -N12C • Billing Address –N1BT • Party to Receive copy of notices (Not bills) – N1PK • Number of Load Mgmt water heaters – AMTL0 (use when changing quantity to zero) • Number of Load Mgmt air conditioners – AMT5J (use when changing quantity to zero) • Special Meter Configuration (net meter removal)		

3. 867 Historical Usage / 867 Historical Interval Usage – PTD Loop

Segment:	**REF Reference Identification (KY=Special Meter Configuration)**
Position:	030
Loop:	PTD
Level:	Detail
Usage:	Optional
Max Use:	20
Purpose:	To specify identifying information
Syntax Notes:	**1** At least one of REF02 or REF03 is required.
	2 If either C04003 or C04004 is present, then the other is required.
	3 If either C04005 or C04006 is present, then the other is required.
Semantic Notes:	**1** REF04 contains data relating to the value cited in REF02.
Comments:	
PA Use:	Required when special meter configuration is present on an account
NJ Use:	Not Used
DE Use:	Not Used
MD Use:	Not Used
Example:	REF*KY* NMSUN000000000

Data Element Summary

	Ref. Des.	Data Element	Name	X12 Attributes	
Must Use	**REF01**	**128**	**Reference Identification Qualifier**	**M**	**ID 2/3**
			Code qualifying the Reference Identification		
			KY — Site Specific Procedures, Terms, and Conditions Special Meter Configuration		
Must Use	**REF02**	**127**	**Reference Identification**	**X**	**AN 1/30**
			Reference information as defined for a particular Transaction Set or as specified by the Reference Identification Qualifier		

ASUN	Net Metering Solar
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NWST	Non-Net Metering Waste
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NFOS	Non-Net Metering Fossil Fuel
NMLT	Non-Net Metering Multiple Different Sources

ORDER NO. 83423

IN THE MATTER OF A REVIEW OF THE PRICE TO COMPARE PUBLISHED BY MARYLAND'S INVESTOR-OWNED ELECTRIC UTILITIES	* * * * * * *	BEFORE THE PUBLIC SERVICE COMMISSION OF MARYLAND CASE NO. 9228

To: The Parties of Record and Interested Persons

In this Order, we find that the "Price to Compare" ("PTC") that currently appears on Maryland electric customers' bills no longer serves its well-intentioned purpose. Rather than providing a helpful apples-to-apples point of comparison for offers from alternative electric suppliers, we find that the PTCs published by Maryland's Investor-Owned Electric Utilities ("IOUs") are confusing, can be misleading, and will often be dated. Given how Standard Offer Service ("SOS") electricity is bought, it is impossible to boil SOS prices down to one number that characterizes those prices accurately over the life of the contracts suppliers are likely to offer. For that reason, customers need more than just a weighted average. And although weighted average information has its value, that value is diminished by the suggestion, inherent in the term "Price to Compare," that customers need look no further.

After considering the filings of the parties in this case and the arguments presented at a hearing on June 1, 2010, we direct each of the IOUs to replace the PTC on customer bills, and the "Price to Compare" terminology, with: (1) the current and known future SOS prices, properly labeled and with effective dates; (2) the date beyond which SOS prices are unknown; and (3) a weighted average of known SOS prices, with the date through which that average is effective. We direct the IOUs to update this information as soon as possible after new residential SOS procurements and to provide this same SOS price information on their websites. We also find that the IOUs should provide more detailed SOS pricing information on their websites, and we direct them to submit proposed templates and formats for review, comment and approval.[1]

Background

In Case No. 8908, the Commission approved a settlement that established the "wholesale competitive procurement methodology to implement utility provided Standard Offer Service ("SOS") to Maryland's retail electric customers after their utility-specific restructuring settlements expire."[2] Among other things, that settlement established the process through which the IOUs currently procure electricity to serve SOS customers and the way that the IOUs would recover the costs they incur in providing SOS electricity. As the Order notes, the settlement also provided that "customers eligible for Standard Offer Service will be notified of the retail prices for SOS and the price to compare for the next service year at least two months prior to the beginning of the service year."[3]

Over the last year or so, the Commission has adopted new choice-related consumer protection regulations[4] and devoted substantial time and attention to the arduous process of implementing them. Over the course of those proceedings, as well as the discussion of choice issues during the 2010 Session of the General Assembly, it became apparent that the existing PTC needed a fresh look. If, as the supplier

[1] This proceeding deals only with the PTC. We have not considered, and offer no opinion here, on the nature or extent of other information relating to alternative electricity supply that IOUs must provide on their websites or in any other forum.
[2] Order No. 78400, *In the Matter of the Commission's Inquiry into the Competitive Selection of Electricity Supplier/Standard Offer Service*, Case No. 8908, at 1 (April 24, 2003).
[3] *Id*. at 12; *see also* Settlement § 15.
[4] *See generally* Code of Maryland Regulations ("COMAR") 20.53.

community has promised, the impending onset of Purchase of Receivables increases the number of suppliers making offers to residential customers, it will be all the more important for customers to have accurate and useful information at their fingertips. And as utility customers ourselves, we have reviewed the PTC on our bills and realized that it raises as many questions as it answers.

On April 13, 2010, then, we issued a Notice Initiating Proceeding and Setting a Procedural Schedule, which opened this case for the purpose of investigating "whether the 'price to compare' calculated by the IOUs and set forth on customers' monthly bills is an effective tool that facilitates or influences a customer's decision whether to select a competitive electric supplier and provides sufficient and accurate information to make the comparison between the competitive offers and Standard Offer Service provided by the customer's IOU." The Notice asked the IOUs a series of questions about their PTCs, and sought comments more generally on the question of what PTC would be of most use to customers:

> Questions for Utilities
>
> - How are you calculating the price to compare?
> - How is the price to compare displayed on the bill?
> - Does any explanation accompany the price to compare number on the bill? If so, what is that explanation?
> - Where is the price to compare found and how is it displayed on your website?
> - How often does the price to compare get updated?
> - What are the costs and other implications of listing more than one price to compare, *e.g.*, the current and next Standard Offer Service price along with the applicable dates of each?
>
> Question for Commenters
>
> - What calculation and display of the price to compare would be of most use to customers, and why?

We received and reviewed comments from a broad array of parties.[5] We also held a legislative-style hearing on June 1, 2010, at which we heard comments from panels comprised of IOUs, electricity suppliers and trade associations, OPC and the Commission Staff.

Analysis

This case asks whether the companies' existing PTC methodology and format provide helpful information to customers and, if not, whether they should be changed or augmented. As it turns out, however, there is no uniform PTC methodology or format – the IOUs calculate PTCs at different times and in different ways. BGE[6] and the PHI companies[7] periodically (and at different intervals)[8] calculate a PTC that weights the summer and non-summer rates in proportion to a single average customers' usage during those periods. Allegheny calculates a new PTC each month, but bases it only on the customer's rate and usage for that month rather than projecting a customer's costs into the future.[9] This is not a criticism – Order No. 78400 did not define *how* the utilities should calculate the PTC, nor are we aware of any other Order of this Commission specifying a particular format – but it is a threshold problem that needs to be fixed. Fortunately, the IOUs all appear to use the same fundamental inputs in their PTC

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[5] In addition to the IOUs, we received and reviewed comments from our Staff; the Office of People's Counsel ("OPC"); the Montgomery County Office of Consumer Protection; and the National Energy Marketers Association ("NEMA"), Washington Gas Energy Services ("WGES"), MXenergy Electric, Inc. ("MX") and Strategic Communications, LLC (collectively, "Suppliers").

[6] Response of Baltimore Gas and Electric Company ("BGE Response") at 1-2; Transcript of Hearing, June 1, 2010 ("Tr."), at 12.; Comments of Delmarva Power & Light Company ("Delmarva Comments") at 1; Comments of Potomac Electric Power Company ("Pepco Comments") at 1; Tr. 53.

[7] Delmarva Comments at 1; Pepco Comments at 1.

[8] BGE and Delmarva calculate their Prices to Compare twice a year, BGE Response at 3 and Tr. 13-14; while Pepco calculates it only once. Tr. 65. These differences are based entirely on history, not on any decision by the Commission. *Id*. at 66. Moreover, the timing of the SOS procurement auctions has never really permitted the IOUs to disclose the Price to Compare two months ahead of schedule, as the settlement in Case No. 8908 contemplated. Tr. 10.

[9] Allegheny Power's Responses ("Allegheny Responses"), at 1; Tr. 76, 79-80.

calculations, *i.e.*, the costs of generation, transmission, and other charges that would be avoided by the IOU if a customer bought his or her supply elsewhere.[10]

In light of the questions we directed to them, the IOUs' written comments focused understandably on the current state of the PTC rather than on suggesting ways to make it more helpful to customers. To the extent they expressed a preference, the IOUs argued generally in favor of the *status quo*, positing that other PTC formulations could lead to new customer confusion.[11] Nevertheless, they expressed a willingness to consider other approaches to the PTC,[12] including plans already under way by BGE to update its PTC more frequently.[13] As we requested, the IOUs also provided some general estimates of the cost of listing more than one PTC on customer bills, ranging from "not expected to be significant"[14] to approximately $4,000[15] to "extensive programming changes" that would require "at least 600 hours of Information Technology development, programming and implementation."[16]

In their comments, the supplier community objected to PTC calculations that reflect an average of SOS prices on the ground that they mask market conditions. Instead, the Suppliers argued that the PTC should reflect that SOS procurement takes place twice a year or more and should "unbundle" and disclose all of the components of the price (such as the different elements comprising the IOUs' SOS administrative

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[10] Allegheny Responses, at 1; BGE Response at 1-2; Delmarva Comments at 1; Pepco Comments at 1.
[11] *See* Delmarva Comments at 4; Pepco Comments at 4; Allegheny Response at 3-4.
[12] *See, e.g.*, Tr. 11 (BGE).
[13] BGE Response at 3; Tr. 13-14.
[14] Delmarva Comments at 4; Pepco Comments at 4.
[15] BGE Response at 4.
[16] Allegheny Response at 3.

charges).[17] On questioning from the Commission, NEMA and WGES agreed that requiring separated summer and winter rates and an average rate would be an improvement over the current PTC.[18] MX was more concerned about ensuring that consumers understand that the current SOS procurement process in Maryland leads to summer and winter rates.[19] RESA favored retaining a PTC, and liked the idea of an average annualized number, although it offered no specific proposal on how to improve the PTC or related disclosures to provide customers enough information.[20] RESA also recommended that the bill refer customers to a website for more information.[21] And WGES argued that the PTC should be adjusted to reflect new SOS rates as the auctions occur, rather than a weighted average or a projection.[22]

OPC contended that load-weighted average PTCs are misleading and cannot be fixed.[23] In OPC's view, a weighted average PTC suggests to consumers that they will pay the PTC price for the entire year ahead. OPC contends that the impact of switching for an individual consumer may vary a great deal from the impact a PTC-times-usage calculation might yield, depending on when the customer performs this analysis and which tranches of SOS supply the PTC includes. Instead, OPC argued that IOUs should abandon the PTC (and indeed, objects to the term "Price to Compare"), and disclose the

[17] *See*, *e.g*., NEMA Comments 4-8. The Suppliers also contend that the PTC does not capture all of the costs the utilities incur in providing SOS. NEMA's comments, at 7, list a group of costs that the PTC should encompass, and the Suppliers raise questions about whether certain of them are contained in the utilities' "administrative charges." In particular, NEMA questions whether the utilities' PTCs include scheduling and control area services, risk management premiums, load shape costs, commodity acquisition and portfolio management, administrative and general expenses, metering, billing, information exchange, compliance with consumer protection regulations and customer care. We decline NEMA's invitation to unpack the specific components of each IOU's PTC and revisit at this point the list of costs that should be included.

[18] Tr. at 110, 156-57.

[19] Tr. at 116-18, 134.

[20] Tr. at 125-27.

[21] Tr. at 126-29.

[22] Tr. at 129-33.

[23] Tr. at 136 *et seq*.

current and future SOS prices, the date on which SOS prices no longer are known, and the fact that switching takes 2-6 weeks to take effect. OPC also recommended that we: (a) clarify the schedule for notifying customers of new SOS rates; (b) require that any approved PTC should appear on *all* customers' bills, even if customers already have switched; and (c) direct that bills include 12-13 months of usage data, as Allegheny's and Pepco's bills already do.

Commission Staff cautioned us against changing the PTC abruptly, but recommends that we retain a weighted average PTC method updated twice per year and augment the PTC with the current and known future SOS prices.[24] Staff argued that customers understand the current PTC, and that although individual experience might vary, the weighted average PTC is helpful. Staff argued that customers with more precise questions can always call the Commission or the IOUs or suppliers to get more detailed information, and expressed the view that customers should rely more on suppliers for information about switching. Staff acknowledged that a weighted average PTC can become stale toward the end of each SOS season, especially so if the seasonal differential is bigger. But Staff believes that consumers are better off with a weighted average PTC than without it, and that we should err on the side of providing more information from which customers can do their own analysis rather than eliminating information that theoretically could be misleading.

We begin our analysis, as always, with the law. The PTC first came into being as part of the settlement approved in Order No. 78400.[25] That Order relied generally on the provisions of the Public Utility Companies Article relating to Maryland's transition to a

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[24] Tr. at 161 *et seq*.
[25] *In the Matter of the Commission's Inquiry into the Competitive Selection of Electricity Supplier/Standard Offer Service*, Case No. 8908 (April 24, 2003).

restructured electricity market,[26] and specifically on § 7-510(c), which defined the parameters of the competitive process through which the IOUs would procure electricity to serve SOS customers. The Order does not discuss the PTC at length or define a specific source of authority for that portion of the settlement. Rather, the PTC came about as one of the many components of the overall SOS procurement process, and it seems to have been left alone in the time since.

Although the Commission never cited it in Order No. 78400, we find statutory direction in § 7-505(b)(4)(i). That provision, which also is part of the broader restructuring legislation, requires electric companies and suppliers to provide accurate information about the services they offer to customers:

> The Commission shall, by regulation or order, require each electric company and electricity supplier to provide adequate and accurate information to each customer on the available electric services of the electricity or electricity supplier . . . .[27]

Although this provision goes on to require certain specific disclosures unrelated to the PTC, the statutory list is not exclusive.[28] And the underlying principle makes sense in this context: anyone selling electricity to customers in Maryland, by virtue of an SOS obligation or not, should provide adequate and accurate information about those services. In addition to our broader charge to "establish customer choice of electric supply and

[26] *See generally* PUC §§ 7-501-518.
[27] PUC § 7-505(b)(4)(i).
[28] After the quoted passage, § 7-505(b)(4)(i) states that the disclosures shall "include[e] disclosure, every 6 months, of a uniform common set of information about:

1. the fuel mix of electricity purchased by customers, including categories of electricity from coal, natural gas, nuclear, oil, hydroelectric, solar, biomass, wind, and other resources, or disclosure of a regional fuel mix average; and
2. the emissions, on a pound per megawatt-hour basis, of pollutants identified by the Commission, or disclosure of a regional fuel mix average."

electric supply services"[29] and our overarching supervisory power over public service companies,[30] we hold that the law specifically authorizes us to ensure that company disclosures relating to the terms and conditions of electric service are adequate and accurate, and thus to review and revise the PTC.

These principles govern, of course, the information provided to customers in all rate classes. But we are especially concerned about the PTC for residential customers, who are left generally to work through the complexities of choice for themselves (unlike commercial customers, who often rely on consultants). A broader array of market entrants and product offerings in Maryland could well bring opportunities for customers, but also could increase the opportunities for customers to be misled or confused. Although there has been electric choice in Maryland for years, the overwhelming majority of residential customers still pay a set price for electricity supply that changes twice per year, and that is what they know and understand. As we work through these issues, we have to presume that, at least at this writing, the average Maryland electric customer does not understand the components of the price he or she pays, and that he or she will not be in a position to analyze the impact of switching providers unless the IOUs provide useful points of comparison.

These principles, and the record in this case, lead us to three key conclusions.

First, the same information should appear on customer bills across the State. For all of the IOUs except Allegheny, the PTC is meant to serve as a proxy for the customer's supply cost in the months to follow. The BGE and PHI PTCs project known future rates and assumptions about customer usage to get a single, weighted number that is meant to

[29] PUC § 7-504(1).
[30] PUC §§ 2-112 and 2-113.

be comparable to a supplier's fixed, per-kWh offer. That can itself be confusing, particularly if the results of SOS auctions are announced publicly and discussed in the press (as they have been of late). Allegheny's PTC, on the other hand, takes the rate in place during the billing period and the customer's usage during that period and calculates the PTC at that snapshot in time. Allegheny neither discloses nor takes account of future rate changes, including those that are known. So although Allegheny's methodology seems superficially to be more individualized than the others', it does not attempt to project a customer's cost of electricity beyond the most recent billing period.

We find no reason to have company-to-company differences on the information disclosed in the bill. To the contrary, all Maryland electric customers should have access to the same information and the same opportunity to make informed decisions. Accordingly, we direct all of the IOUs to revise their bill disclosures to comply with this Order.

Second, customers need more pricing information than the PTC currently provides. Although the current SOS price appears on every bill, it is not identified consistently across the IOUs' bills, and in at least one case is combined with other charges.[31] Future SOS prices do not appear at all. And although the weighted average of future SOS prices can provide a valuable basis for comparing a customer's expenditure over some period of time, the blended "price" disclosed in the BGE and PHI PTCs will invariably differ from the actual SOS price customers are paying at any given moment. Depending on when in the lifecycle of the PTC the customer refers to it, the BGE and

[31] Delmarva's bill form combines SOS supply and transmission, which Pepco breaks out separately. Put another way, the bills vary even within corporate families.

PHI PTCs could well be stale – especially for Pepco customers, who currently wait a full year for the PTC to be refreshed.

We find that customers will be in the best position to evaluate supplier offers if they have both the raw price figures and the weighted average at the ready. We also agree with OPC that the term "Price to Compare" could itself contribute to customer confusion by suggesting that the customer need look only at that one number. Accordingly, we direct the IOUs to replace the "Price to Compare" (and the "Price to Compare" terminology) with a listing of current and known SOS prices and a weighted average of known SOS prices, including effective dates (the "SOS Pricing Information"), labeled in the following manner:

> **Supply**[32] **Price Comparison Information**: The current price for Standard Offer Service electricity is x.x cents/kWh, effective through [date]. Standard Offer Service electricity will cost x.x cents/kWh beginning on [date] through [date]. The price of Standard Offer Service electricity after [date] has not yet been set. The weighted average price of Standard Offer Service electricity will be x.x cents through [date].

The weighted average shall be calculated in the manner that BGE and PHI calculate their current PTCs, but the IOUs shall update it (and the SOS price figures) as soon as possible after every SOS procurement auction so that the numbers reflect all known SOS rates.

This information should be provided on *all* customers' bills, no matter who supplies the customer's electricity supply. The IOUs also should provide all of this information on their websites, but should not be limited on their websites to what can be included on the bill. Because this case has not focused as closely on the IOUs' websites,

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[32] This word should track the term the IOU uses on the bill to describe the customer's electricity supply charges so that the customer knows which price would be replaced.

we direct the IOUs to submit additional filings describing the pricing information currently available on their websites, any additional information they would propose to provide, and proposed templates and formats for review, comment and approval.

Third, we find the historical usage information currently provided on the Allegheny, Delmarva and Pepco bills helpful and useful (although it is sometimes difficult to interpolate the kWh figures themselves from the graphs). The weighted average methodology accounts for average usage patterns, but individual customers' usage may vary considerably from that average. With a year's worth of their own usage history, customers will be able to calculate their own individual impact more precisely. What we do not know, however, is whether requiring individual usage information would be disproportionately costly or complex from a programming perspective. We suspect not, since three of the four IOUs already include it and BGE included it in the past. Nevertheless, we direct the IOUs, in their follow-up filings in this case, to discuss the cost, programming and other implications were we to require them to include 12 months of customer usage information, with actual kWh figures, on each customer's bill.

IT IS THEREFORE, this 24th day of June, in the year Two Thousand Ten by the Public Service Commission of Maryland,

ORDERED: (1) That each Maryland investor-owned utilities shall no later than August 1, 2010 replace its current "Price to Compare" message on its bill with the following "SOS Pricing Information" message:

> **[Supply] Price Comparison Information**: The current price for Standard Offer Service electricity is x.x cents/kWh, effective through [date]. Standard Offer Service electricity will cost x.x cents/kWh beginning on [date] through [date]. The price of

> Standard Offer Service electricity after [date] has not yet been set. The weighted average price of Standard Offer Service electricity will be x.x cents through [date]; and

(2) That each Maryland investor-owned utility shall file with the Commission, by August 2, 2010:

(a) a description of the pricing information currently available on its website, a description of any additional information that it would propose to provide about the SOS Pricing Information and proposed templates and formats; and

(b) information on the cost, programming and any other implications if the Commission were to require the Maryland investor-owned utilities to include 12 months of customer usage information, with actual kWh figures, on each customer's bill.

By Direction of the Commission,

/s/ Terry J. Romine

Terry J. Romine
Executive Secretary

COMMONWEALTH OF PENNSYLVANIA
PENNSYLVANIA PUBLIC UTILITY COMMISSION
P.O. BOX 3265, HARRISBURG, PA 17105-3265

March 19, 1999

To: Electric Generation Suppliers

This letter addresses a problem with the EGS portion of the EDC combined (single) bill format that has been brought to the Commission Staff's attention. Specifically, the generation and transmission charges of the EGS are not properly presented on the bill. A number of the EGSs are not transmitting the data through EDI to the EDCs in a manner that complies with the Customer Information Regulations, 52 Pa. Code §§ 54.1-54.9, and the Secretarial Letters clarifying the presentation of such charges on bills.

In order to remedy this situation, the Commission Staff offers the following acceptable formats as guidance to the EGSs. Specifically, shown below are acceptable formats for "labels" and "standard pricing units", which are the two components to the presentation of EGS generation and transmission charges on bills. The "label" refers to the naming of the charges, while the "standard pricing unit" relates to the presentation of price and usage. Since the Commission's regulations require the charges to appear on a single line on the bill, it is necessary for EGSs to combine an acceptable label and an acceptable standard pricing unit on a single line. The formats presented below apply to all EDC territories where EGSs are procuring both generation and transmission services for customers. In service areas where EDCs are continuing to acquire transmission services for EGSs' customers, the only variation from the formats shown below involves the "label." In particular, where an EDC has retained billing responsibility for transmission charges, the acceptable "label" options are "Generation Charges" or "Generation."

I. The following are the acceptable "Labels:"

   A. Generation and Transmission Charges
   B. Generation & Transmission Charges
   C. Generation and Transmission
   D. Generation & Transmission

II. The following are the acceptable "Standard Pricing Units."

A. Units of Energy Used x Price

1. 1,500 kWh x $0.0375	$56.25
2. 1,500 kWh x 3.75¢	$56.25
3. 1,500 kWh @ $0.0375	$56.25
4. 1,500 kWh @ 3.75¢	$56.25

B. Price x Units of Energy Used

5. $0.0375 x 1,500 kWh	$56.25
6. 3.75¢ x 1,500 kWh	$56.25
7. $0.0375 @ 1,500 kWh	$56.25
8. 3.75¢ @ 1,500 kWh	$56.25

Thank you for your cooperation in this matter and I ask that you direct any questions to David Mick of the Bureau of Consumer Services at 717-783-3232.

Sincerely yours,

Mitchell Miller

Mitchell Miller, Director
Bureau of Consumer Services

cc: Electric Distribution Companies

PA Electronic Data Exchange Working Group

June 15, 2011

Dear OCMO / CHARGE Staff,

During the June 2nd, 2011 EDEWG meeting, the group was unable to reach consensus on approving EDI Change Control #87 (p. 2-7 below). EDI Change Control #87 was submitted by Phil McCauley (BlueStar Energy) to add the effective date of the Peak Load Contribution (PLC) & Network Service Peak Load (NSPL) values to the EDI 867 Historical Usage (HU) and Historical Interval Usage (HI) transaction sets. This would permit the EDCs to report the effective dates for both the current and future PLC/NSPL values. Today, only the current value is provided within the HU/HI transaction. This change control resolves the current issue where the non-incumbent EGS cannot receive the future PLC value via EDI until after June 1st, once the PLC value becomes "current". EDEWG leadership met separately and agreed EDI Change Control #87 should apply to all EDCs in Pennsylvania thus making the change mandatory.

No EGS has oppossed this EDI Change Control, to the contrary, EGSs need both the current and future PLC/NSPL values to accurately price and bill customers. By having future Capacity PLC values at the same time as the current values, this will enable customers to not only benefit from movements in the market, but also ensure their capacity related costs can be minimized.

The EDCs each reported their positions regarding EDI Change Control #87 as follows…

West Penn Power	Unable to implement due to merger/code freeze, should address under First Energy system as WPP is migrating to FE's SAP system.
First Energy	Supports this change, investigating implementation feasibility / timeline
Duquesne Light Company	Does not object to the change, investigating internally.
UGI Utilities	Does not object to the change, investigating internally.
PPL Electric Utilities	Stated this change is a good idea, investigating internally.
PECO	Will not support without a cost recovery mechanism.

EDEWG requests CHARGE add EDI Change Control #87 to the meeting agenda. EDEWG also requests that CHARGE attempt to obtain statewide approval of EDI Change Control #87 for EDC implementation with a documented timeline for each EDC. In the event CHARGE is unable to do so, EDEWG requests CHARGE make a formal recommendation and escalate EDI Change Control #087 to the Commission for a final decsion.

Sincerely,
/s/ Brandon S. Siegel
EDEWG EDI Change Control Manager

EDEWG Change Request #087

This EDEWG Change Request can be found on the PUC website at
http://www.puc.state.pa.us/electric/electric_edewg_download.aspx

Requester's Name: Phil McCauley	**EDC/EGS Name**: BlueStar Energy	**Phone #** : 312 628-8610
Date of Request: 4/20/2011	**Affected EDI Transaction Set #(s)**: 867HU and 867HIU	**E-Mail Address**: pmccauley@bluestarenergy.com
Requested Priority (emergency/high/low): Low	**Requested Implementation Date**: 12/1/2011	**Status**: Open; non-consensus – escalated to PUC Staff / CHARGE

Brief Explanation (This will be copied into the description in the Change Control Summary Spreadsheet):

Use DTM segments to add an effective date range for the PLC & NSPL values provided in the 867HU and 867HIU transaction sets.

Detail Explanation (Exactly what change is required? To which EDEWG Standards? Why?):
What is required?

Add clarification to the QTYKC and QTYKZ segments regarding the looping structure presenting current and future PLC and NSPL values.

Add required DTM segments for each PLC and NSPL value (Capacity *and* Transmission) provided in the PTD*FG loop of an 867HU/HIU transaction. This change requires:
- DTM01 code (007=Effective Date) to signify that the DTM06 value signifies a date range
- DTM05 code (RD8) to define the formatting of the DTM06 value as CCYYMMDD-CCYYMMDD
- DTM06 value (formatted as CCYYMMDD-CCYYMMDD)

This method of assigning a date range to NSPL/PLC values is currently utilized in Illinois and described in the IL 867HU guide. The use of DTM05/06, and the codes described above, providing a date range is also documented in the old UIG 867 implementation guide.

Which EDEWG Standards are modified?

The change affects the 867HU / HIU - PTD*FG loop. Add a DTM segment to the QTY*KC and QTY*KZ loops within PTD*FG, as in the below example:

```
PTD*FG~
REF*BF*14~
QTY*KC*153.27*K1~
DTM*007****RD8*20100601-20110531~
QTY*KZ*127.6589*K1~
DTM*007****RD8*20110101-20111231~
QTY*KC*116.2223*K1~
DTM*007****RD8*20110601-20120531~
```

The second QTY/DTM segments containing "future" PLC values will only be provided during the time of year in which they are available (typically January to May for PLC and November to December for NSPL)

Why this is important?
Suppliers need to know the effective dates of PLC values that are provided in the 867HU/HIU transactions. When future PLCs are available, the suppliers would like to be provided both the current and the future PLC values, and the associated date ranges. Both values are needed (when available) in order to accurately price and bill customers.

EXAMPLE REDLINE TO BOTH 867HI and 867HIU PROVIDED BELOW

The PA EDEWG leadership met on 4/25 and agreed this change would apply to all EDC's in PA who are PJM participants.

For Change Control Manager Use Only:

Date of EDEWG Discussion: 5/12/2011, 6/2/2011	Expected Implementation Date: TBD	

EDEWG Discussion and Resolution:

4/20/2011-Brandon Siegel: Reviewed request w/BlueStar, added into EDI CC tracking log, assigned #087, sent to list server & placed on 5/12 agenda.

5/12/2011-Brandon Siegel: EDEWG discussed CC87. EDCs unable to approve until consulting internally. EDEWG requests EDCs to report back with implementation timeline during the June meeting. CC87 remains open pending further discussion.

6/2/2011-Brandon Siegel: EDEWG discussed this change in detail. Suppliers support this change as it will provide the future PLC/NSPL values by automated electronic means not available today. The EDC's position regarding EDI CC 87 is as follows:
WPP: under a code freeze due the FE merger, needs addressed under FE's system.
FE: supports CC87, investigating feasibility of implementing.
DLC: does not object to the change, investigating internally.
UGI: does not object to the change, investigating internally.
PPLEU: stated CC87 is a good idea, investigating internally.
PECO: will not support EDI CC87 without cost recovery.

Due to PECO's non-support, EDEWG is unable to reach consensus on EDI Change Control 87. The EDI Change Control manager will escalate to PUC staff for resolution.

6/15/2011-Brandon Siegel: escalated to PUC Staff.

Priority Classifications

Emergency Priority	*Implemented within 10 days or otherwise directed by EDEWG*
High Priority	*Changes / Enhancements implemented with 30 days. The next release, or as otherwise directed by EDEWG*
Low Priority	*Changes / Enhancements implemented no earlier than 90 days, Future Release, or as otherwise directed by EDEWG*

Please submit this form via e-mail to both the PUC at annmarino@state.pa.us ***and to the Change Control Manager, Brandon Siegel at*** bsiegel@ista-na.com

Your request will be evaluated and prioritized at an upcoming EDEWG meeting or conference call.

Segment:	**QTY** **Quantity (KC=Peak Load Contribution)**
Position:	110
Loop:	QTY
Level:	Detail
Usage:	Optional
Max Use:	1
Purpose:	To specify quantity information
Syntax Notes:	**1** At least one of QTY02 or QTY04 is required. **2** Only one of QTY02 or QTY04 may be present.
Semantic Notes:	**1** QTY04 is used when the quantity is non-numeric.
Comments:	
Notes:	Each QTY/MEA/DTM loop conveys consumption information about one metering period.
PA Use:	Required for PJM participants. The QTY/DTM loop may be sent twice depending on the time of year the Historical Usage is being provided. (PLC is effective June 1 - May 31) One iteration will show the current PLC and a second iteration will show the PLC that will be effective in the period defined in the DTM segment. Currently the PA EDCs change the PLC effective June 1st. Once the EDCs are aware of what the next effective PLC will be (typically in December) they should begin providing it on transactions. For example, in February 2010 the PLC values would be reported as: QTY*KC*476*K1 DTM*007****RD8*20090601-20100531 QTY*KC*450*K1 DTM*007****RD8*20100601-20110531 Whereas in September 2010 the PLC value would include only one loop because the following year's PLC is undetermined: QTY*KC*450*K1 DTM*007****RD8*20100601-20110531
NJ Use:	Required. This will be the Peak Load Contribution in effect when the transaction is requested. **NJ Note:** PSE&G sends Capacity Obligation to PJM.
DE Use:	Same as NJ
MD Use:	Required for PJM participants.
Example:	QTY*KC*752*K1

Data Element Summary

	Ref. Des.	Data Element	Name	Attributes
Must Use	**QTY01**	**673**	**Quantity Qualifier** Code specifying the type of quantity KC — Net Quantity Decrease Peak Load Contribution: Peak load contributions provided to PJM for Installed Capacity calculation (coincident with PJM Peak).	**M ID 2/2**
Must Use	**QTY02**	**380**	**Quantity** Numeric value of quantity	**X R 1/15**
Must Use	**QTY03**	**355**	**Unit or Basis for Measurement Code** Code specifying the units in which a value is being expressed, or manner in which a measurement has been taken K1 — Kilowatt Demand Represents potential power load measured at predetermined intervals	**M ID 2/2**

Segment:	**DTM** **Date/Time Reference (007=PLC Effective Date)**
Position:	210
Loop:	QTY
Level:	Detail
Usage:	Optional
Max Use:	10
Purpose:	To specify pertinent dates and times
Syntax Notes:	**1** At least one of DTM02 DTM03 or DTM05 is required.
	2 If DTM04 is present, then DTM03 is required.
	3 If either DTM05 or DTM06 is present, then the other is required.
Semantic Notes:	
Comments:	
PA Use:	Required for PJM Participants The QTY/DTM loop may be sent twice depending on the time of year the Historical Usage is being provided. (PLC is effective June 1 - May 31) One iteration will show the current PLC and a second iteration will show the PLC that will be effective in the period defined in the DTM segment. Currently the PA EDCs change the PLC effective June 1st. Once the EDCs are aware of what the next effective PLC will be (typically in December) they should begin providing it on transactions. For example, in February 2010 the PLC values would be reported as: QTY*KC*476*K1 DTM*007****RD8*20090601-20100531 QTY*KC*450*K1 DTM*007****RD8*20100601-20110531 Whereas in September 2010 the PLC value would include only one loop because the following year's PLC is undetermined: QTY*KC*450*K1 DTM*007****RD8*20100601-20110531
NJ Use:	Not Used
DE Use:	Not Used
MD Use:	Not Used
Example:	DTM*007****RD8*20070601-20080531

Data Element Summary

	Ref. Des.	Data Element	Name	Attributes	
Must Use	**DTM01**	**374**	**Date/Time Qualifier** Code specifying type of date, or time, or both date and time	**M**	**ID 3/3**
			007 Effective PLC Effective Date		
Must Use	**DTM05**	**1250**	**Date/Time Period Format Qualifier** Code indicating the date format, time format, or date and time format	**X**	**ID 2/3**
			RD8 Range of Dates Expressed in Format CCYYMMDD-CCYYMMDD		
Must Use	**DTM06**	**1251**	**Date/Time Period** Expressed as CCYYMMDD-CCYYMMDD	X	**AN 1/35**

Segment:	**QTY** **Quantity (KZ=Network Service Peak Load)**
Position:	110
Loop:	QTY
Level:	Detail
Usage:	Optional
Max Use:	1
Purpose:	To specify quantity information
Syntax Notes:	**1** At least one of QTY02 or QTY04 is required. **2** Only one of QTY02 or QTY04 may be present.
Semantic Notes:	**1** QTY04 is used when the quantity is non-numeric.
Comments:	
Notes:	Each QTY/MEA/DTM loop conveys consumption information about one metering interval.
PA Use:	Required for PJM participants. The QTY/DTM loop may be sent twice when the Utility is providing both the current NSPL and the NSPL that will be effective for a subsequent period. This will occur for short period of time between when the future value is sent via the 814C and the effective date of the future value. For example, you may receive either two loops: QTY*KZ*476*K1 DTM*007****RD8*20100101-20101231 QTY*KZ*450*K1 DTM*007****RD8*20110101-20111231 Or just one: QTY*KZ*450*K1 DTM*007****RD8*20110101-20111231
NJ Use:	Required. This will be the Network Service Peak Load in effect when the transaction is requested. **NJ Note:** PSE&G sends Capacity Obligation to PJM.
DE Use:	Same as NJ
MD Use:	Required for PJM participants.
Example:	QTY*KZ*752*K1

Data Element Summary

	Ref. Des.	Data Element	Name	Attributes
Must Use	**QTY01**	**673**	**Quantity Qualifier** Code specifying the type of quantity KZ — Corrective Action Requests - Written Network Service Peak Load: Customer's peak load contribution provided to PJM for the Transmission Service calculation (coincident with LDC peak).	**M ID 2/2**
Must Use	**QTY02**	**380**	**Quantity** Numeric value of quantity	**X R 1/15**
Must Use	**QTY03**	**355**	**Unit or Basis for Measurement Code** Code specifying the units in which a value is being expressed, or manner in which a measurement has been taken K1 — Kilowatt Demand Represents potential power load measured at predetermined intervals	**M ID 2/2**

Segment:	**DTM** **Date/Time Reference (007=NSPL Effective Date)**
Position:	210
Loop:	QTY
Level:	Detail
Usage:	Optional
Max Use:	10
Purpose:	To specify pertinent dates and times
Syntax Notes:	**1** At least one of DTM02 DTM03 or DTM05 is required.
	2 If DTM04 is present, then DTM03 is required.
	3 If either DTM05 or DTM06 is present, then the other is required.
Semantic Notes:	
Comments:	
PA Use:	Required for PJM Participants NSPL is for January 1 - December 31 The QTY/DTM loop may be sent twice when the Utility is providing both the current NSPL and the NSPL that will be effective for a subsequent period. This will occur for short period of time between when the future value is sent via the 814C and the effective date of the future value. For example, you may receive either two loops: QTY*KZ*476*K1 DTM*007****RD8*20100101-20101231 QTY*KZ*450*K1 DTM*007****RD8*20110101-20111231 Or just one: QTY*KZ*450*K1 DTM*007****RD8*20110101-20111231
NJ Use:	Not Used
DE Use:	Not Used
MD Use:	Not Used
Example:	DTM*007****RD8*20070601-20080531

Data Element Summary

	Ref. Des.	Data Element	Name	Attributes	
Must Use	**DTM01**	**374**	**Date/Time Qualifier** Code specifying type of date, or time, or both date and time 007 Effective NSPL Effective Date	**M**	**ID 3/3**
Must Use	**DTM05**	**1250**	**Date/Time Period Format Qualifier** Code indicating the date format, time format, or date and time format RD8 Range of Dates Expressed in Format CCYYMMDD-CCYYMMDD	**X**	**ID 2/3**
Must Use	**DTM06**	**1251**	**Date/Time Period** Expressed as CCYYMMDD-CCYYMMDD	X	**AN 1/35**