Monitoring Analytics

REPORT TO THE VIRGINIA STATE CORPORATION COMMISSION: Congestion in the AEP Service Territory in Virginia

The Independent Market Monitor for PJM

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Overview of Congestion Calculations

This report provides details of congestion associated with American Electric Power's (AEP Virginia) service territory within the state of Virginia for the periods of October 1, 2007, to September 30, 2008 (2007/2008), and October 1, 2008, to September 30, 2009 (2008/2009). Congestion calculations are for the entire territory and not for any specific organization; the total congestion calculations are the sum of all the congestion calculations for the organizations with market activity in the area. The report also includes congestion event hours for the constraints which had the largest impact on congestion charges in AEP Virginia, either positive or negative, and the congestion charges associated with each constraint.[1]

Total congestion costs equal load congestion payments minus generation congestion credits plus explicit congestion costs. Net congestion costs equal load congestion payments minus generation congestion credits.[2] Explicit congestion is the net congestion cost associated with point-to-point energy transactions. Each of these categories of congestion costs are comprised of day-ahead and balancing congestion costs. Day-ahead congestion is based on day-ahead MW while balancing congestion is based on deviations between day-ahead and real-time MW.[3]

Table 1 and Table 2 provide a summary of the total congestion charges in the Virginia portion of AEP. Table 1 shows a summary of the congestion costs associated with the Virginia portion of the AEP service territory since October 2007. In addition, Table 2 shows a monthly breakdown of congestion costs.

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1 Congestion event hours are hours in which a transmission constraint is binding. In the day ahead, an interval equals one hour. In real time, an interval equals five minutes. In order to have a consistent metric for day-ahead and real-time congestion frequency, real-time congestion frequency is measured using the convention that an hour is constrained if any one of its component five-minute intervals is constrained.

2 Prior to June 1, 2007, PJM Congestion Accounting methods included Implicit Congestion Costs, Spot Congestion Costs, and Explicit Congestion Costs. Effective June 1, 2007, PJM ceased calculating spot congestion costs. Implicit congestion costs are now equal to the difference between load congestion payments and generation congestion credits. Explicit Congestion Costs remained the same after June 1, 2007.

3 See Table 16, "Congestion Definitions," for a summary of relevant definitions.

Table 1 Total AEP Virginia congestion costs (Dollars (Millions)): October 1, 2007 through September 30, 2009.

	Congestion Costs	Percent Change
2007/2008	($86.4)	NA
2008/2009	($9.2)	89%
Total	($95.7)	

Table 2 Monthly AEP Virginia congestion costs (Dollars (Millions)): October 1, 2007 through September 30, 2009.

	Total Congestion Costs		
	2007	2008	2009
Jan		($7.7)	($5.3)
Feb		($6.9)	$1.6
Mar		($6.4)	$2.5
Apr		($10.2)	($0.7)
May		($10.0)	$0.1
Jun		($11.8)	$0.8
Jul		($13.8)	($0.8)
Aug		($6.1)	($1.4)
Sept		($7.1)	($0.4)
Oct	$1.1	($2.2)	
Nov	($4.1)	($2.4)	
Dec	($3.6)	($1.0)	

Congestion charges can be both positive and negative. When a constraint binds, the price effects of that constraint vary. The system marginal price (SMP) is uniform for all areas, while the congestion components of LMP will either be positive or negative in a specific area, meaning that actual LMPs are above or below the SMP.[4] The area affected by a constraint will have increased prices and the unconstrained area will have lower prices. If an area is located downstream from the constrained element, the area will experience positive congestion costs. If an area is located upstream from the constrained element, the area will experience negative congestion costs (lower prices).

Day ahead congestion charges and credits are based on MW and LMP in the Day-Ahead Energy Market. Balancing congestion charges and credits are based on load or generation deviations between the Day-Ahead and Real-Time Energy Markets and LMP

[4] The SMP is the price of the distributed load reference bus. The price at the reference bus is equivalent to the five minute real-time or hourly day-ahead load weighted PJM LMP.

in the Real-Time Energy Market. If a participant has real-time generation or load that is greater than its day ahead generation or load then the deviation will be positive. If there is a positive load deviation at a bus where real-time LMP has a positive congestion component, positive balancing congestion costs will result. Similarly, if there is a positive load deviation at a bus where real-time LMP has a negative congestion component, negative balancing congestion costs will result. If a participant has real-time generation or load that is less than its day ahead generation or load then the deviation will be negative. If there is a negative load deviation at a bus where real-time LMP has a positive congestion component, negative balancing congestion costs will result. Similarly, if there is a negative load deviation at a bus where real-time LMP has a positive congestion component, negative balancing congestion costs will result.

In order to provide a more detailed explanation of the congestion calculations from which the total congestion charges are derived, each category of congestion is defined and a table of the congestion charges or credits associated with each category is provided.

Net Congestion Bill

The net congestion bill is defined by PJM settlements. The net congestion bill is calculated by subtracting generating congestion credits from load congestion payments. The logic is that increased congestion payments by load are offset by increased congestion revenues to generation for the area analyzed. Whether the net congestion bill is an appropriate measure of congestion for load depends on who pays the load congestion payments and who receives the generation congestion credits. The net congestion bill is an appropriate measure of congestion for a utility that charges load congestion payments to load and credits generation congestion credits to load. The net congestion bill is not an appropriate measure of congestion in situations where load pays the load congestion payments but does not receive the generation credits as an offset.

Load congestion payments are netted against generation congestion credits on an hourly basis, by participant, and then summed for the given period. Generation credits result either from the direct ownership of generation or from the purchase of supply from another entity via a bilateral transaction.

Both Day-ahead and Balancing Load Congestion Payments and Generation Congestion Credits are calculated.

- **Day-ahead Load Congestion Payments.** Day-ahead load congestion payments are calculated for all cleared demand, decrement bids, and day ahead energy sale transactions. (Decrement bids and energy sales can be thought of as scheduled load.) Day-ahead load congestion payments are calculated using load MW and the

congestion component of LMP (CLMP) for the load bus, decrement bid location, or the source of the sale transaction, as applicable.

- **Day-ahead Generation Congestion Credits.** Day-ahead generation congestion credits are calculated for all cleared generation, increment offers and day-ahead energy purchase transactions. (Increment offers and energy purchases can be thought of as scheduled generation.) Day ahead generation congestion credits are calculated using generation MW and the CLMP for the generator bus, increment offer location, or the sink of the purchase transaction, as applicable.

- **Balancing Load Congestion Payments.** Balancing load congestion payments are calculated for all deviations between a PJM participant's real-time load and energy sale transactions and their day ahead cleared demand, decrement bids, and energy sale transactions. Balancing load congestion payments are calculated using MW deviations and the real-time CLMP for each bus where a deviation from a member's day ahead scheduled load exists.

- **Balancing Generation Congestion Credits.** Balancing generation congestion credits are calculated for all deviations between a PJM participant's real-time generation and energy purchase transactions and the day ahead cleared generation, increment offers and energy purchase transactions. Balancing generation congestion credits are calculated using MW deviations and the real-time CLMP for each bus where a deviation from a member's day ahead scheduled generation exists.

Explicit Congestion Costs

Explicit Congestion costs are the congestion costs associated with moving energy from one specific point to another across the transmission system. Such point-to-point transactions may be either internal to PJM or be import or export transactions.

- **Internal Purchases.** For internal purchases the Explicit Congestion costs equal the difference in CLMPs between the sink bus and source bus of the purchase multiplied by the transacted MW. The buyer pays the congestion costs associated with internal purchases.

- **Import and Export Transactions.** For point-to-point and network secondary transmission customers, the Explicit Congestion costs equal the difference in CLMPs between the sink bus and source bus multiplied by the transacted MW. The transmission customer pays the congestion costs associated with an import or export transaction.

The Explicit Congestion Costs calculated for the Virginia portion of AEP represent the costs associated with point-to-point transactions that sink in the Virginia portion of AEP. For example, if a transaction is sourced in Pennsylvania and sinks in AEP Virginia, the

charges would be based on the MW of the transaction multiplied by the difference between the sink CLMP and the source CLMP. The resulting congestion costs are allocated to the zone and state of the sink location, in this case AEP Virginia. The sink location is the buyer's location and reflects the cost to the buyer of the internal purchase or external transaction.

Table 3 shows the combined day ahead and balancing load congestion payments, generation congestion credits, and explicit congestion costs for the AEP Virginia service territory for the 24-month period from October 1, 2007, to September 30, 2009. Table 4 shows the congestion costs categories separated by day-ahead and balancing to show the contributions from both the Day-Ahead and Real-Time Energy Markets.

Table 3 Total AEP Virginia congestion costs by category: October 1, 2007 through September 30, 2009.

Congestion Costs (Millions)					
	Load Payments	Generation Credits	Net Congestion Bill	Explicit	Grand Total
2007/2008	($109.3)	($12.9)	($96.5)	$10.0	($86.4)
2008/2009	($13.8)	($0.5)	($13.3)	$4.1	($9.2)

Table 4 Total day-ahead and balancing AEP Virginia congestion costs by category: October 1, 2007 through September 30, 2009.

Congestion Costs (Millions)									
	Day Ahead				Balancing				
	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total
2007/2008	($96.3)	($10.8)	$10.2	($75.3)	($13.1)	($2.0)	($0.1)	($11.2)	($86.4)
2008/2009	($13.8)	($2.0)	$4.2	($7.6)	($0.0)	$1.5	($0.1)	($1.6)	($9.2)

Table 5 lists the top 15 constraints affecting AEP Virginia congestion costs for the period beginning October 1, 2007, and ending September 30, 2008.[5] Table 5 also provides the type of constraint (Line, Transformer, or Interface), the location of the constraint and the congestion event hours for the period analyzed. Table 5 and Table 7 illustrate that constraints outside of the AEP control zone, such as the Mount Storm – Pruntytown line in AP or the Dickerson – Pleasant View line in Pepco, can impact the AEP congestion costs.

Table 5 Top 15 constraints affecting AEP Virginia congestion costs: October 1, 2007 through September 30, 2008.

				Event Hours	
				Day	Real
No.	Constraint	Type	Location	Ahead	Time
1	Cloverdale - Lexington	Line	AEP	3,734	1,786
2	AP South	Interface	500	2,319	830
3	Axton	Transformer	AEP	466	0
4	West	Interface	500	1,253	534
5	Kammer	Transformer	500	2,928	1,623
6	Kanawha - Matt Funk	Line	AEP	90	80
7	5004/5005 Interface	Interface	500	863	430
8	Mount Storm - Pruntytown	Line	AP	1,550	782
9	Central	Interface	500	946	30
10	Danville - East Danville	Line	Dominion	646	147
11	Mount Storm	Transformer	AP	907	460
12	Axton - Jacksons Ferry	Line	AEP	119	0
13	Bedington - Black Oak	Interface	500	2,530	585
14	Cloverdale	Transformer	AEP	207	210
15	East	Interface	500	546	11

[5] The top 15 constraints are determined based on the absolute value of total congestion costs for the period.

Table 6 shows the congestion cost details for the top 15 constraints affecting AEP Virginia for the period beginning October 1, 2007, and ending September 30, 2008. The Cloverdale – Lexington line had the largest impact on congestion costs with a total of negative $60.4 million or 70 percent of total congestion costs. The AP South Interface was the second largest contributor to congestion costs in AEP Virginia during the 2007/2008 period with negative $18.3 million. The Axton transformer, a facility located within AEP Virginia, had the largest positive contribution to congestion costs with positive $9.7 million.

Table 6 Congestion cost details for the top 15 constraints affecting AEP Virginia: October 1, 2007 through September 30, 2008.

	Congestion Cost Deltas (Millions)								
	Day Ahead				Balancing				
Constraint	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total
Cloverdale - Lexington	($58.3)	($3.2)	($1.6)	($56.8)	($3.7)	$0.1	$0.3	($3.6)	($60.4)
AP South	($19.6)	($1.3)	$1.3	($17.1)	($2.5)	($1.2)	$0.1	($1.3)	($18.3)
Axton	$7.6	$0.1	$2.2	$9.7	$0.0	$0.0	$0.0	$0.0	$9.7
West	($6.0)	($0.3)	$0.1	($5.6)	($0.8)	($0.1)	$0.0	($0.6)	($6.2)
Kammer	($6.6)	($0.5)	$1.3	($4.8)	($1.6)	($0.2)	$0.1	($1.3)	($6.1)
Kanawha - Matt Funk	$4.7	$0.4	$0.7	$5.0	($0.1)	$0.3	($0.2)	($0.7)	$4.4
5004/5005 Interface	($3.9)	($0.2)	$0.2	($3.5)	($0.6)	$0.1	$0.0	($0.7)	($4.2)
Mount Storm - Pruntytown	$1.6	($1.9)	$2.3	$5.8	($0.9)	$0.9	($0.3)	($2.1)	$3.7
Central	($3.1)	($0.2)	($0.0)	($3.0)	$0.0	($0.0)	$0.0	$0.0	($2.9)
Danville - East Danville	($2.3)	($0.2)	($0.7)	($2.9)	($0.2)	($0.4)	$0.1	$0.3	($2.6)
Mount Storm	$1.4	($0.5)	$1.0	$3.0	($0.3)	$0.5	($0.2)	($1.0)	$1.9
Axton - Jacksons Ferry	$1.4	($0.0)	$0.4	$1.8	$0.0	$0.0	$0.0	$0.0	$1.8
Bedington - Black Oak	($1.5)	($1.6)	$2.3	$2.4	($0.6)	$0.1	($0.0)	($0.8)	$1.7
Cloverdale	$1.5	($0.4)	$0.4	$2.3	($0.2)	$0.4	($0.1)	($0.7)	$1.6
East	($1.5)	($0.1)	($0.0)	($1.4)	$0.0	($0.0)	$0.0	$0.0	($1.4)

Table 7 lists the top 15 constraints affecting AEP Virginia congestion costs for the period beginning October 1, 2008, and ending September 30, 2009. Table 7 also provides the type of constraint (Line, Transformer, or Interface), the location of the constraint and the congestion event hours for the period analyzed.

Table 7 Top 15 constraints affecting AEP Virginia congestion costs: October 1, 2008 through September 30, 2009.

				Event Hours	
				Day	Real
No.	Constraint	Type	Location	Ahead	Time
1	Cloverdale - Lexington	Line	AEP	1,341	642
2	West	Interface	500	884	103
3	AP South	Interface	500	3,949	651
4	Kammer	Transformer	500	4,492	1,696
5	5004/5005 Interface	Interface	500	953	325
6	Mount Storm - Pruntytown	Line	AP	1,538	173
7	Ruth - Turner	Line	AEP	704	288
8	Kanawha River	Transformer	AEP	261	73
9	Dunes Acres - Michigan City	Flowgate	Midwest ISO	3,266	1,079
10	Dickerson - Pleasant View	Line	Pepco	416	107
11	Kanawha River - Bradley	Line	AEP	48	15
12	East Frankfort - Crete	Line	ComEd	1,962	0
13	Wylie Ridge	Transformer	AP	359	404
14	Sammis - Wylie Ridge	Line	AP	1,840	609
15	Kanawha - Kincaid	Line	AEP	291	0

Table 8 shows the congestion cost details of the top 15 constraints affecting AEP Virginia for the period beginning October 1, 2008, and ending September 30, 2009. The Cloverdale – Lexington line had the largest impact on congestion costs with a total of negative $6.0 million or 65 percent of total congestion costs. The AP South interface had the largest positive contribution to congestion costs with positive $4.4 million. The Ruth –Turner line, located in AEP, was the second largest constraint with a positive contribution to congestion costs with positive $1.8 million.

Table 8 Congestion cost details for the top 15 constraints affecting AEP Virginia: October 1, 2008 through September 30, 2009.

	Congestion Cost Deltas (Millions)								
	Day Ahead				Balancing				
Constraint	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total
Cloverdale - Lexington	($6.2)	($0.3)	($0.2)	($6.2)	$0.6	$0.5	$0.1	$0.2	($6.0)
West	($4.8)	($0.2)	$0.0	($4.6)	$0.1	$0.1	$0.0	($0.0)	($4.6)
AP South	$2.2	($1.1)	$1.7	$5.1	($0.5)	$0.1	($0.1)	($0.7)	$4.4
Kammer	($5.1)	($0.2)	$0.8	($4.0)	$0.0	$0.1	($0.0)	($0.1)	($4.1)
5004/5005 Interface	($3.1)	($0.1)	$0.1	($2.8)	$0.3	$0.1	$0.0	$0.2	($2.6)
Mount Storm - Pruntytown	$1.0	($0.4)	$0.7	$2.2	($0.1)	($0.0)	($0.0)	($0.1)	$2.1
Ruth - Turner	$2.1	$0.3	$0.3	$2.0	($0.2)	($0.0)	($0.1)	($0.3)	$1.8
Kanawha River	$1.7	$0.3	$0.2	$1.6	$0.1	$0.0	($0.0)	$0.0	$1.6
Dunes Acres - Michigan City	$2.1	$0.1	($0.8)	$1.2	($0.1)	($0.1)	$0.4	$0.4	$1.6
Dickerson - Pleasant View	($1.6)	($0.1)	($0.1)	($1.6)	$0.1	$0.0	$0.0	$0.1	($1.5)
Kanawha River - Bradley	$1.3	$0.1	$0.1	$1.3	($0.0)	$0.0	($0.0)	($0.0)	$1.3
East Frankfort - Crete	$1.1	$0.0	($0.0)	$1.0	$0.0	$0.0	$0.0	$0.0	$1.0
Wylie Ridge	($0.9)	($0.1)	$0.2	($0.6)	($0.1)	$0.1	($0.0)	($0.3)	($0.9)
Sammis - Wylie Ridge	($1.0)	($0.1)	$0.2	($0.7)	($0.1)	$0.0	($0.0)	($0.1)	($0.9)
Kanawha - Kincaid	$0.8	$0.0	$0.1	$0.9	$0.0	$0.0	$0.0	$0.0	$0.9

Table 9 shows the largest differences (deltas) in congestion costs by constraint for the period ending September 30, 2009 compared to the period ending September 30, 2008. The negative $6.0 million in congestion costs from the Cloverdale – Lexington line represented a $54.4 million, or 90.1 percent, increase in congestion costs from the prior period. The AP South Interface experienced an increase in congestion costs of $22.7 million, from negative $18.3 million to positive $4.4 million. Overall the AEP service territory of Virginia saw an increase in congestion costs of $77.2 million from the 2007/2008 period to the 2008/2009 period.

Table 9 Top 15 constraint congestion cost deltas from the prior period: October 1, 2008 through September 30, 2009 minus October 1, 2007 through September 30, 2008.

	Congestion Cost Deltas (Millions)								
	Day Ahead				Balancing				
	Load	Generation			Load	Generation			Grand
Constraint	Payments	Credits	Explicit	Total	Payments	Credits	Explicit	Total	Total
Cloverdale - Lexington	$52.1	$2.9	$1.4	$50.6	$4.3	$0.3	($0.2)	$3.8	$54.4
AP South	$21.8	$0.2	$0.5	$22.1	$2.1	$1.3	($0.2)	$0.6	$22.7
Axton	($7.1)	($0.1)	($2.0)	($9.0)	($0.1)	$0.0	$0.0	($0.1)	($9.1)
Kanawha - Matt Funk	($4.7)	($0.4)	($0.7)	($5.0)	$0.1	($0.3)	$0.2	$0.7	($4.4)
Central	$3.1	$0.2	$0.0	$2.9	($0.0)	$0.0	($0.0)	($0.0)	$2.9
Danville - East Danville	$2.0	$0.2	$0.7	$2.4	$0.2	$0.4	($0.1)	($0.3)	$2.1
Kammer	$1.5	$0.3	($0.5)	$0.8	$1.6	$0.3	($0.1)	$1.2	$2.0
Mount Storm	($1.4)	$0.5	($1.0)	($2.9)	$0.3	($0.5)	$0.2	$1.1	($1.9)
Axton - Jacksons Ferry	($1.4)	$0.0	($0.4)	($1.8)	$0.0	$0.0	$0.0	$0.0	($1.8)
Ruth - Turner	$2.1	$0.3	$0.3	$2.0	($0.2)	($0.0)	($0.1)	($0.3)	$1.8
Bedington - Black Oak	$1.4	$1.6	($2.2)	($2.4)	$0.6	($0.1)	$0.0	$0.7	($1.7)
Cloverdale	($1.5)	$0.4	($0.4)	($2.3)	$0.1	($0.4)	$0.1	$0.6	($1.7)
Mount Storm - Pruntytown	($0.6)	$1.5	($1.5)	($3.6)	$0.8	($0.9)	$0.3	$2.0	($1.7)
West	$1.2	$0.1	($0.0)	$1.0	$0.8	$0.2	($0.0)	$0.6	$1.6
5004/5005 Interface	$0.9	$0.1	($0.1)	$0.7	$0.9	($0.0)	$0.0	$0.9	$1.6

Conclusion

Congestion costs in the AEP service territory of Virginia increased from 2007/2008 to 2008/2009 by $77.2 million or 89 percent. Load congestion payments increased by $95.5 million from 2007/2008 to 2008/2009, while generation congestion credits increased by $12.4 million from 2007/2008 to 2008/2009. The increase in load congestion payments was partially offset by an increase in generation congestion credits, resulting in an overall increase in the net congestion bill of $83.2 million from 2007/2008 to 2008/2009. Explicit Congestion Costs decreased $5.9 million from the 2007/2008 period to the 2008/2009 period. The Cloverdale – Lexington 500 kV line and the AP South Interface were the top two constraints that contributed to the increase in overall congestion costs in the 2008/2009 period. The increase in congestion costs in the AEP service territory of Virginia was the result of a reduction in negative congestion which resulted from a reduction in the frequency of constraints. The increase was largely due to an overall

decrease in congestion frequency on the Cloverdale – Lexington constraint. This constraint results in lower prices in the AEP Virginia region and higher prices in the Dominion Virginia region.

As the significance of larger, regional constraints decreases, the relative significance of smaller local constraints in AEP increases. This was the case in the 2008/2009 period for the Ruth - Turner line, the Kanawha River transformer, the Kanawha River - Bradley line, and the Kanawha River - Kincaid line. These constraints are all located in AEP and had positive contributions to the 2008/2009 congestion costs.

ARRs and FTRs provide a hedge against congestion costs. The value provided by ARRs and FTRs can also be measured by comparing the credits associated with ARRs and FTRs that sink in a zone to the cost of real time energy in the zone. This is a direct measure of the net price of energy rather than a comparison of the ARR/FTR credits to an accounting measure of congestion. Table 10 shows that from October 1, 2008 through September 30, 2009, the pro rata share of the requested volume of ARRs sunk at AEP Virginia was 8,029 MW and there were 7,955 MW cleared.[6] Out of the 7,955 MW of cleared ARRs, 7,810 MW were self-scheduled as FTRs during the annual FTR auctions. The total value provided by the combination of ARR and self-scheduled FTRs was $34.6 million. Table 10 shows that the total of ARR and self-scheduled FTR credits represented 4.3 percent of the approximately $813.7 million of the total real time energy charges in AEP Virginia.

Table 10 ARR and self-scheduled FTR credits as an offset to energy charges in AEP Virginia: October 1, 2008 through September 30, 2009

ARR Requested MW	ARR Cleared MW	ARR Credits	Self-Scheduled FTR MW	Self-Scheduled FTR Credits	Total Credits	Total Energy Charges	Percent of Energy Charges covered by ARR and Self-Scheduled FTR Credits
8,029	7,955	$626,009	7,810	$34,005,402	$34,631,411	$813,738,353	4.3%

[6] The October to September period spans two planning years. ARRs are pro rated equally to days within each planning year.

Congestion Definitions

Table 11 Congestion Definitions

Congestion Category	Calculation
Day-Ahead Load Congestion Payments	Day-Ahead Demand MWh * Day-Ahead CLMP
Day-Ahead Generation Congestion Credits	Day-Ahead Supply MWh * Day-Ahead CLMP
Day-Ahead Net Congestion Bill	Day-Ahead Load Congestion Payments - Day-Ahead Generation Congestion Credits
Day-Ahead Explicit Congestion Costs	Day-Ahead Transaction MW * (Day-Ahead Sink CLMP - Day-Ahead Source CLMP)
Day-Ahead Total Congestion Costs	Day-Ahead Load Congestion Payments - Day-Ahead Generation Congestion Credits + Day-Ahead Explicit Congestion Costs
Balancing Load Congestion Payments	Balancing Demand MWh * Real-Time CLMP
Balancing Generation Congestion Credits	Balancing Supply MWh * Real-Time CLMP
Balancing Net Congestion Bill	Balancing Load Congestion Payments - Balancing Generation Congestion Credits
Balancing Explicit Congestion Costs	Balancing Transaction MW * (Real-Time Sink CLMP - Real-Time Source CLMP)
Balancing Total Congestion Costs	Balancing Load Congestion Payments - Balancing Generation Congestion Credits + Balancing Explicit Congestion Costs
Total Congestion Costs	Day-Ahead Total Congestion Costs + Balancing Total Congestion Costs

MWh Category	Definition
Day-Ahead Demand MWh	Cleared Demand, Decrement Bids, Energy Sale Transactions
Day-Ahead Supply MWh	Cleared Generation, Increment Bids, Energy Purchase Transactions
Real-Time Demand MWh	Load and Energy Sale Transactions
Real-Time Supply MWh	Generation and Energy Purchase Transactions
Balancing Demand MWh	Real-Time Demand MWh - Day-Ahead Demand MWh
Balancing Supply MWh	Real-Time Supply MWh - Day-Ahead Supply MWh