PJM Markets

Energy and Ancillary Services

PJM State & Member Training Dept.

LMP Basics

What is LMP?

- Locational Marginal Price

- Pricing method PJM uses to:
  - price energy purchases and sales in PJM Market
  - price transmission congestion costs to move energy within PJM RTO
  - price losses on the bulk power system

- Physical, flow-based pricing system:
  - how energy actually flows, NOT contract paths

How does PJM Use LMP?

- Generators get paid at generation bus LMP
- Loads pay at load bus LMP
- Transactions pay differential in source and sink LMP

Economic Dispatch Exercise

MW
$20

Capacity
200 MWs

Not Dispatched

MW
$15

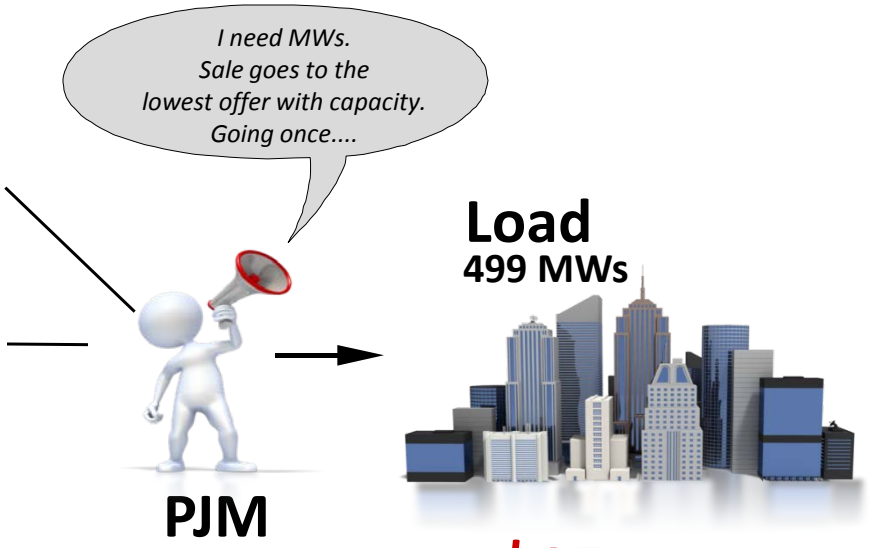
Capacity
200 MWs

199 MWs @ $15

MW
$10

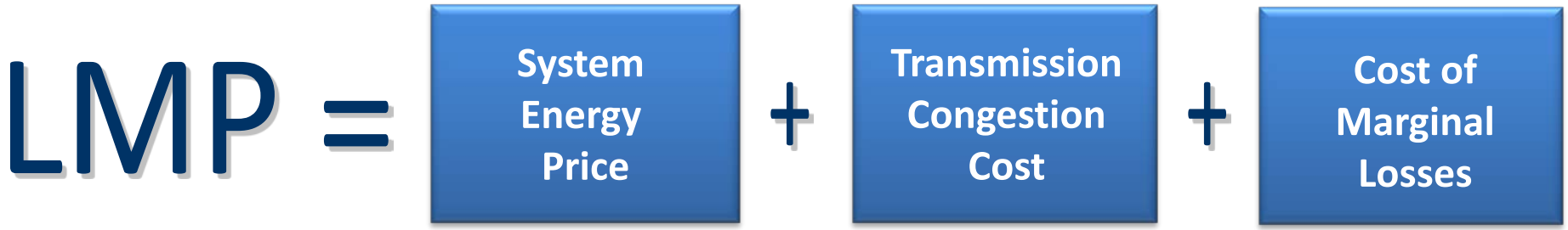
Capacity
300 MWs

300 MWs @ $10



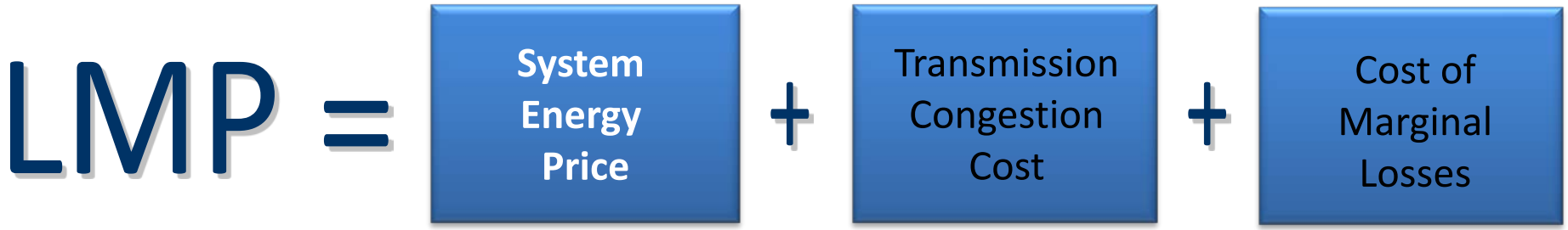
LMP = $15

Locational Marginal Price



LMP is made up of 3 independent components

LMP Components - System Energy Price



☑ System Energy Price

- Represents optimal dispatch ignoring congestion and losses
- Same price for every bus in PJM
- Calculated both in day ahead and real time

LMP Components - System Energy Price

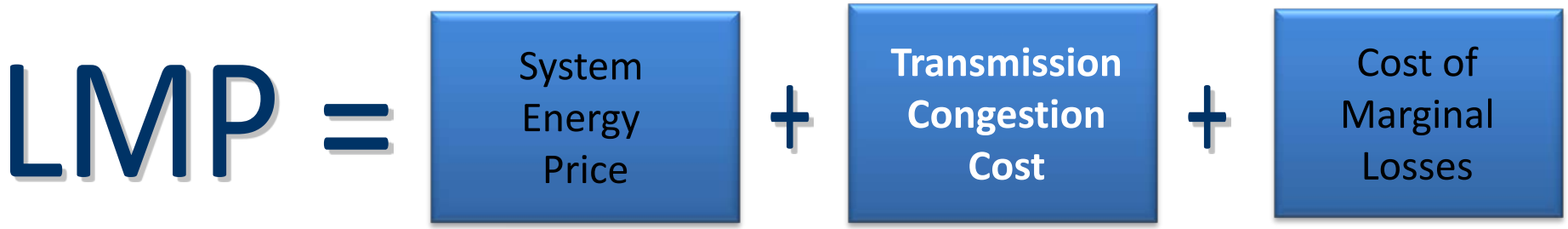
System Energy Price = $20
Congestion =
Losses =
LMP= $20

Dispatch 1500 MW

Transmission path

System Energy Price = $20
Congestion =
Losses =
LMP = $20

LMP Components - Congestion



☑ Congestion Price

- Represents price of congestion for binding constraints
  - Calculated using cost of marginal units controlling constraints and sensitivity factors on each bus
- Will be zero if no constraints
  - Will vary by location if system is constrained
- Calculated both in day ahead and real time

LMP Components - Congestion

System Energy Price =	$20
Congestion =	$30
Losses =	
LMP=	$50

Dispatch 1000 MW

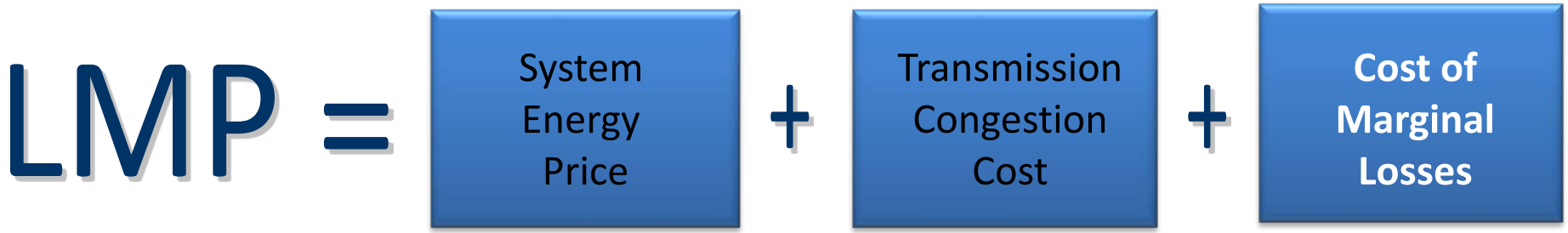
Flow = 1000 MW

Limit = 1000 MW

System Energy Price =	$20
Congestion =	$ 0
Losses =	
LMP =	$20

Dispatch 500 MW

LMP Components - Marginal Losses

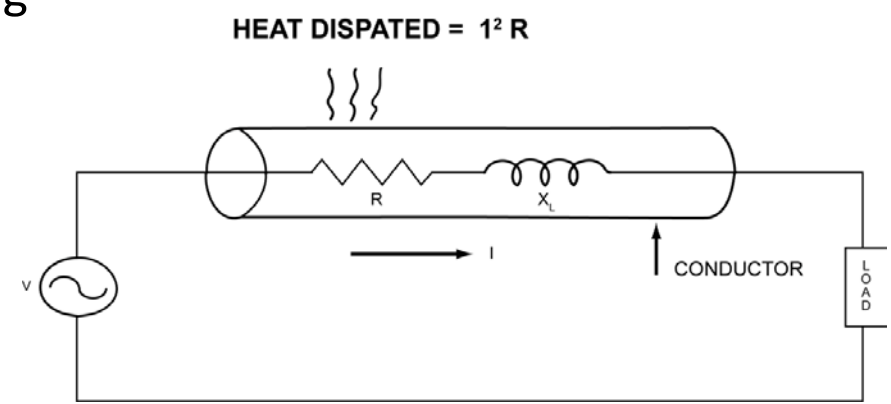


☑ Loss Price

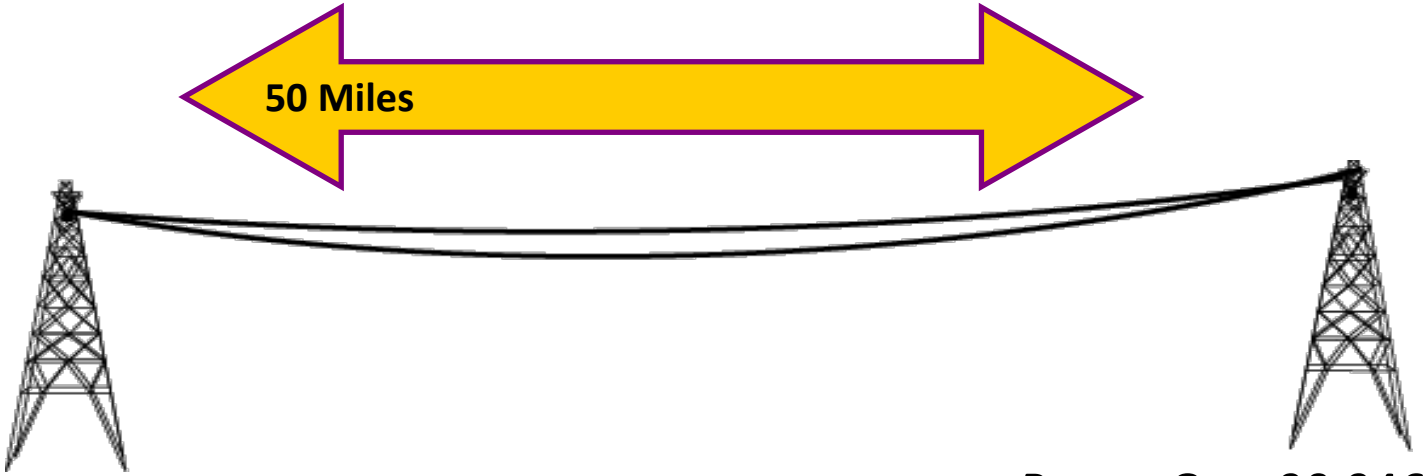
- Represents price of marginal losses
  - Calculated using penalty factors
  - Will vary by location
- Calculated both in day-ahead and real-time

Transmission Losses

- Real Power (MW) Losses
  - Power flow converted to heat in transmission equipment
  - Heat produced by current (I) flowing through resistance (R)
  - Losses equal to I2R
  - Heat loss sets the “thermal rating” of equipment
- Losses increase with:
  - Lower voltage
  - Longer lines
  - Higher current



Transmission Losses



Power In: 100 MW

Voltage In: 235 KV

Current In: 425.53 A

Power Out: 90.946 MW

Power Loss: 9.054 MW

Voltage out: 213.72 KV

Current Out: 425.53 A

LMP Components Marginal Losses

System Energy Price =	$20
Congestion =	$30
Losses =	$ 2
LMP=	$52

Dispatch 1000 MW

Flow = 1000 MW

Limit = 1000 MW

System Energy Price =	$20
Congestion =	$ 0
Losses =	($ 1)
LMP =	$19

Dispatch 500 MW

Two Settlement

What is Two–Settlement?

- It provides PJM Market Participants with the option to participate in a forward market for electric energy in PJM
  - Consists of two markets
  - Separate settlements performed for each market

Two-Settlement Markets

- Day-ahead Market
  - Financial market using Bid-In Load
  - Prices calculated hourly / Hourly settlements
  - Includes virtual bids and price sensitive demand

- Real-time Market
  - Physical Market based on actual system conditions
  - Prices calculated every 5 minutes
  - Hourly Settlements based on deviations from Day-Ahead position

Here's How it Works……..

Today's Price:

10 Gallons

10 Gallons * $3.75 = $37.50

Day-Ahead Settlement

When You Show Up Tomorrow……

Today's Price:

10 Gallons: No Deviation - No Balancing Settlement

12 Gallons: 2 Gallons * $4.00 = $8.00 Balancing Charge

9 Gallons: 1 Gallons * $4.00 = $4.00 Balancing Credit

Day Ahead

Offers Received from Resources

10MW @$30

40MW @$5

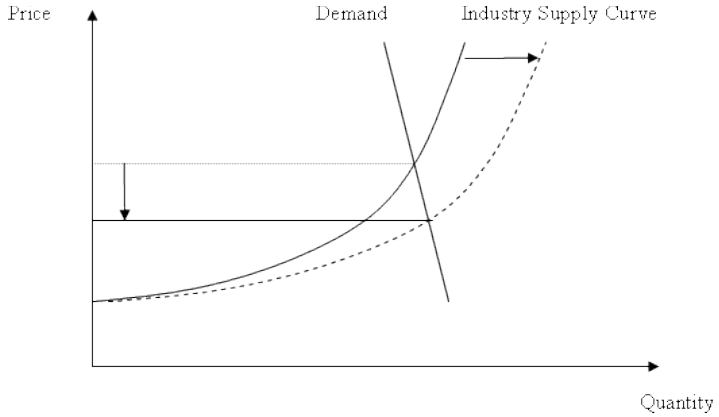
20MW @$10

5MW @$25

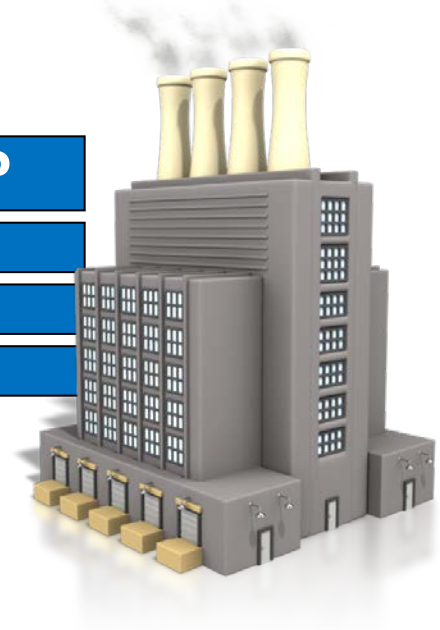
25MW @ $15

Offers Sorted in Increasing Order

100 MW @ $90	5 Offers
125MW @$50	10 Offers
150MW @$25	15 Offers
175MW @$20	20 Offers
195MW @$10	30 Offers



Supply Cleared to Meet Demand

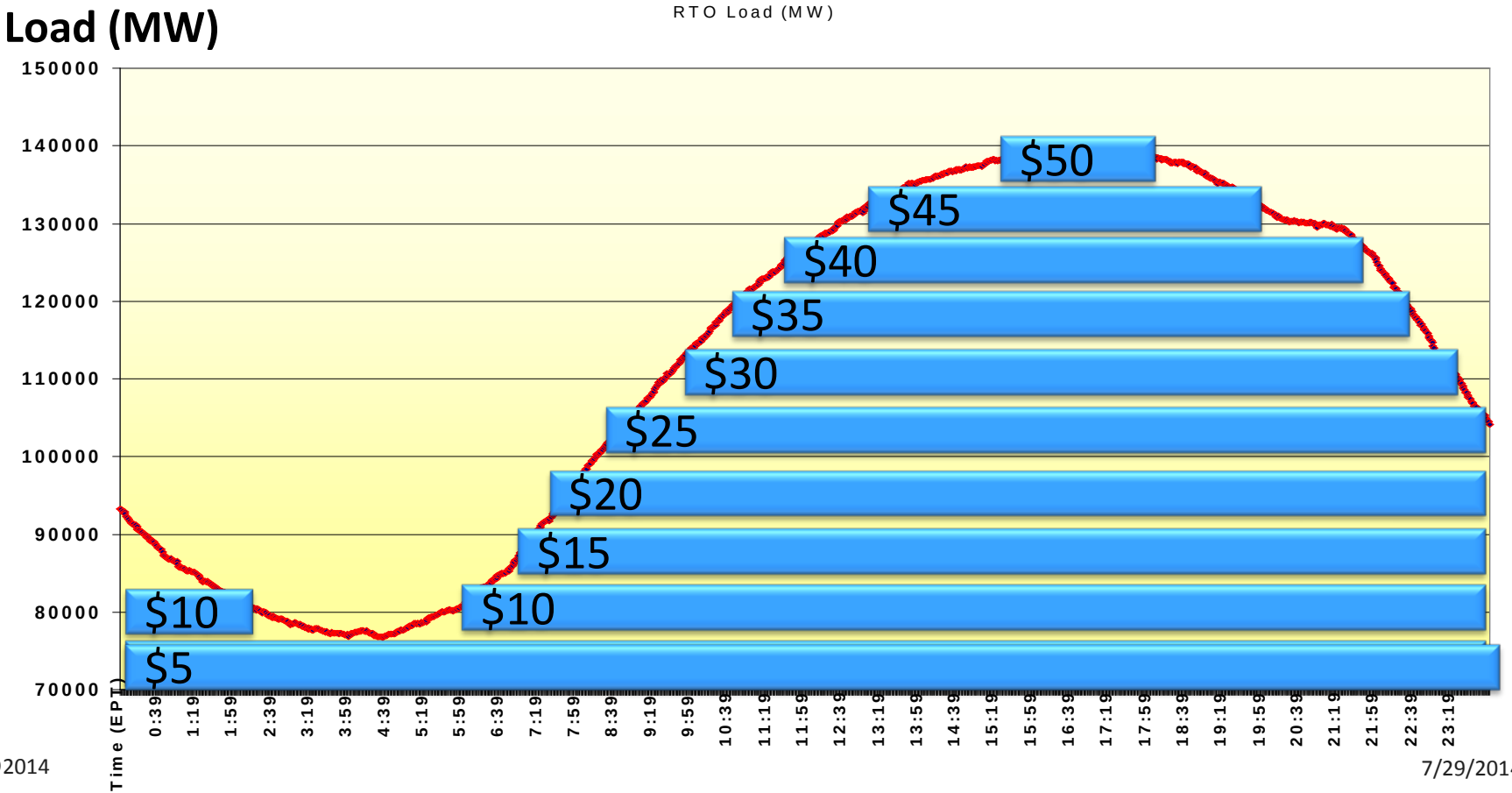


Bid - in Energy Demand

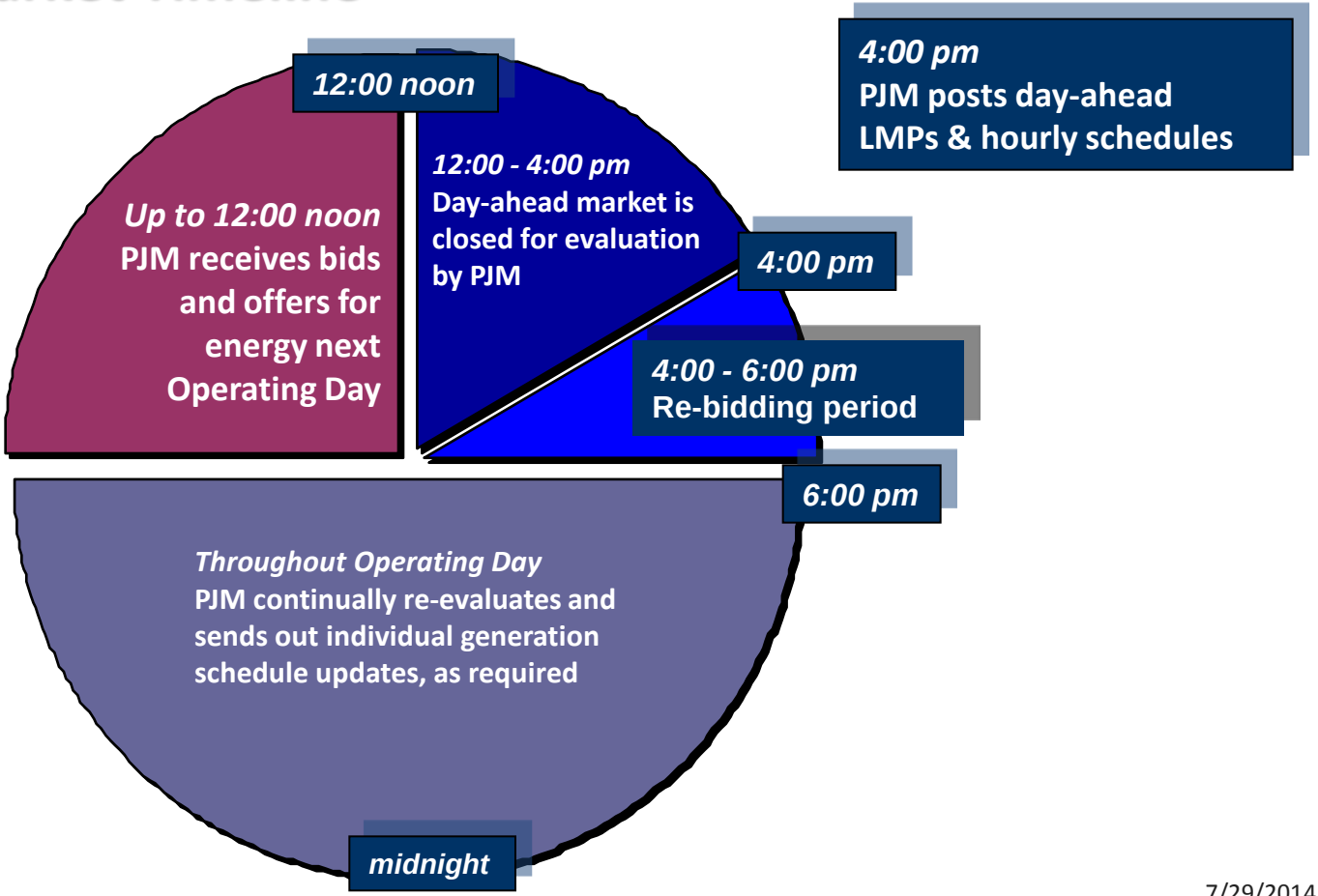
100,000 MW

Resources Scheduled to Meet Demand

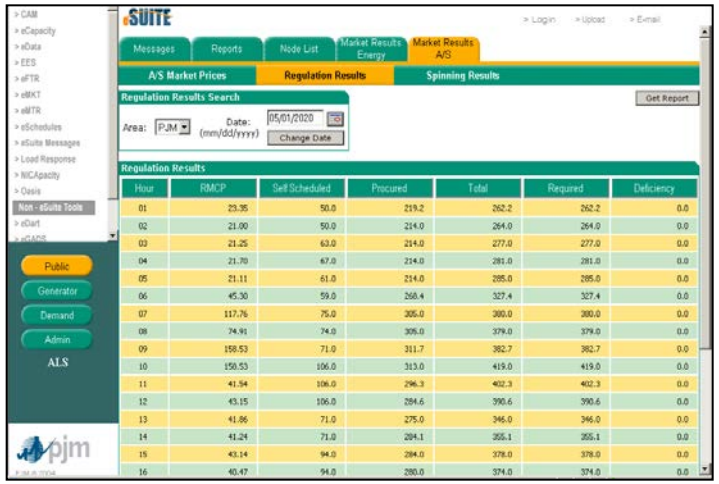
Load (MW)

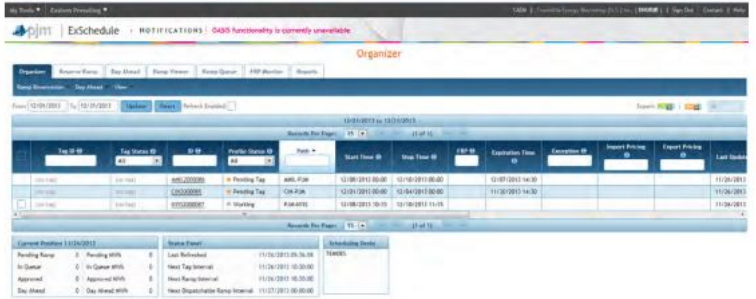


Day-Ahead Market Timeline



Two-Settlement User Interface





eMKT
InSchedules
ExSchedule

Unit bids, load bids
Contracts, Schedules
Physical Schedules

Interacting with PJM Markets

InSchedule

eData

eRPM

Power Meter

eDart

eFTR

Oasis

eFuel

eGADS

eMKT

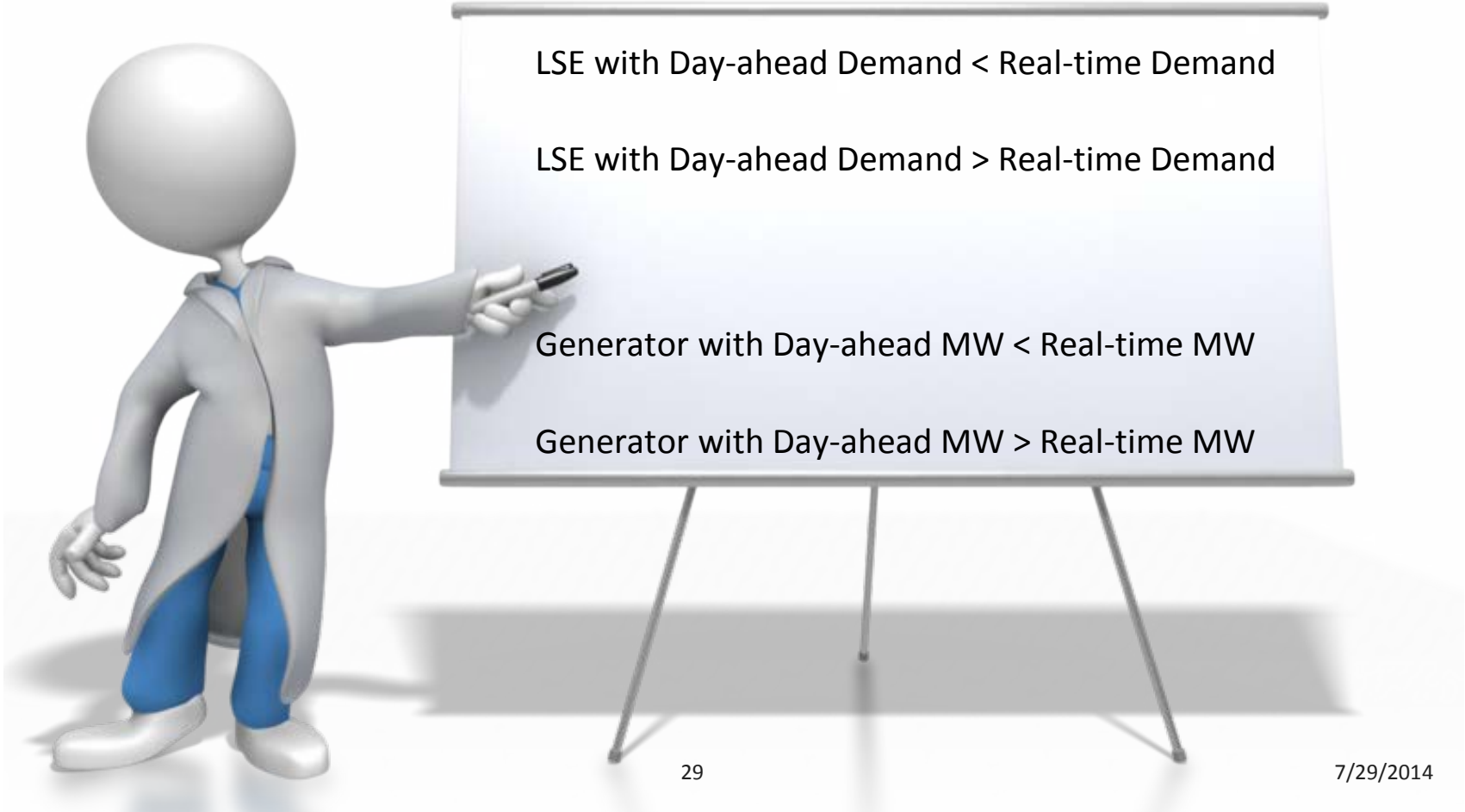
CAM

eLRS

MSRS

ExSchedule

Simple Examples



LSE with Day-Ahead Demand Less than Actual Demand

Day Ahead Market

Scheduled Demand

Real-time Market

Actual Demand

Day Ahead LMP = $20.00

Real-time LMP = $23.00

*$ = 100 * 20.00 = $2000.00 charge*

$ = (105 - 100) 23.00 = $115.00 charge*

$ Total Charge = $2000 + $115 = $2115

LSE with Day-Ahead Demand Greater than Actual Demand

Day Ahead Market

Scheduled Demand

Real-time Market

Actual Demand

Day Ahead LMP = $20.00

Real-time LMP = $23.00

*= 100 * 20.00 = $2000.00 charge*

= (95 - 100) 23.00 = $115.00 credit*

Total Charge = $2000 - $115 = $1885

Generator with Day-Ahead MW Less than Actual MW

Day Ahead Market

Scheduled MW

Real-time Market

Actual MW

Day Ahead LMP = $20.00

Real-time LMP = $22.00

*$ = 200 * 20.00 = $4000.00 credit*

$ = (205 - 200) 22.00 = $110.00 credit*

$ Total Credit = $4000 + $110 = $4110

Generator with Day-Ahead MW Greater than Actual MW

Day Ahead Market

Scheduled MW

Real-time Market

Actual MW
Due to a problem on a unit

Day Ahead LMP = $20.00

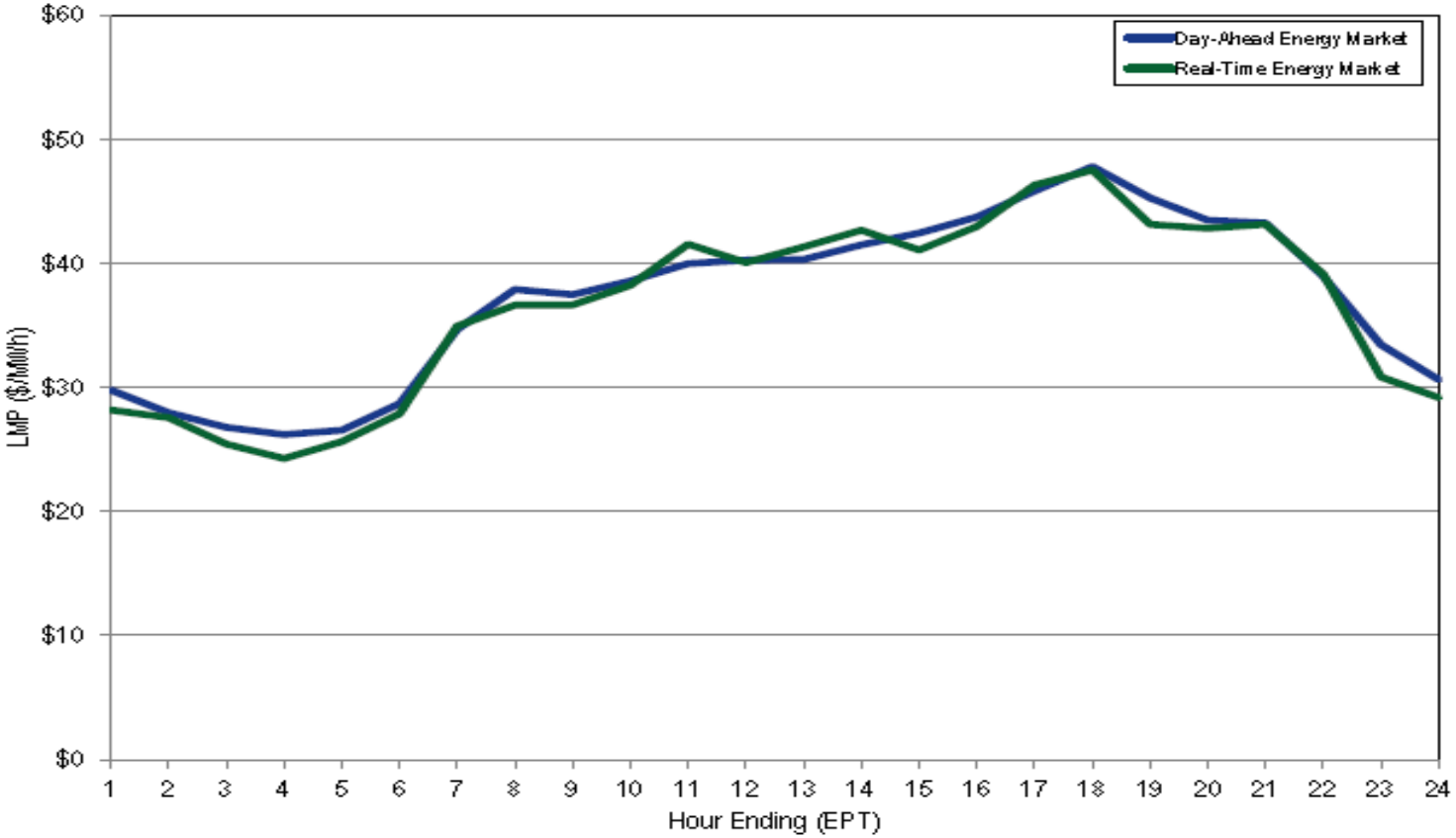
Real-time LMP = $22.00

= 200 * 20.00 = $4000.00 credit

= (100 - 200)* 22.00 = $2200.00 charge

Total Credit = $4000 - $2200 = $1800

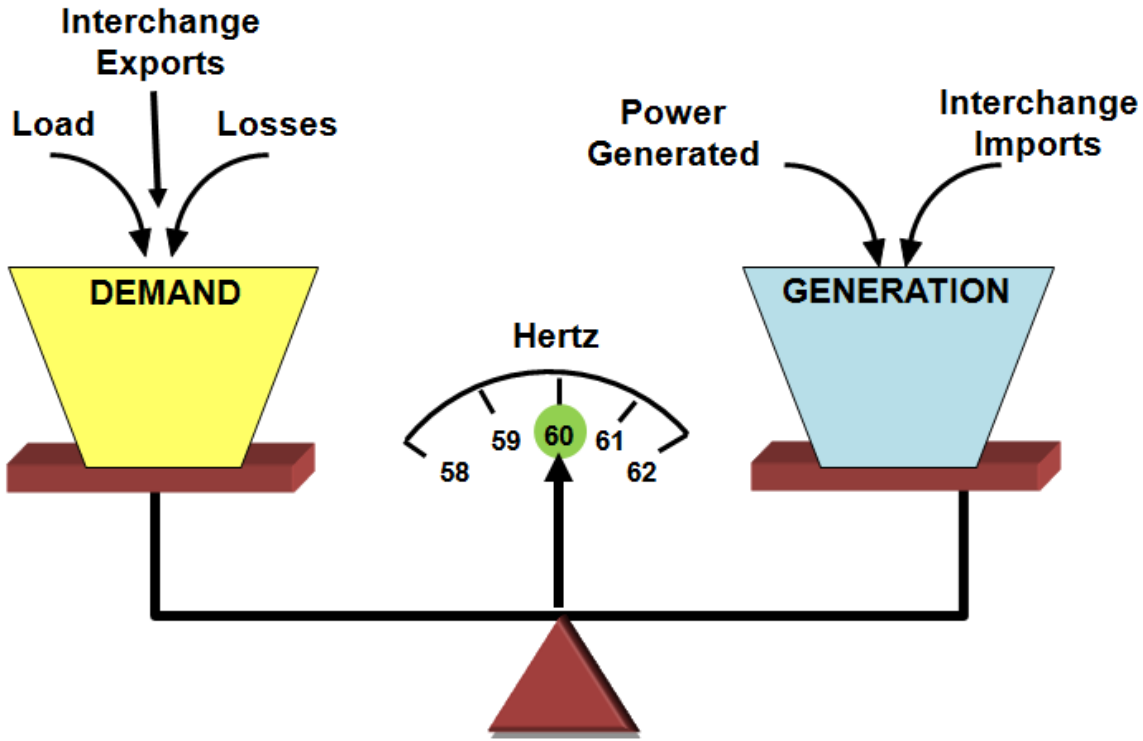
PJM system hourly average LMP: 2013



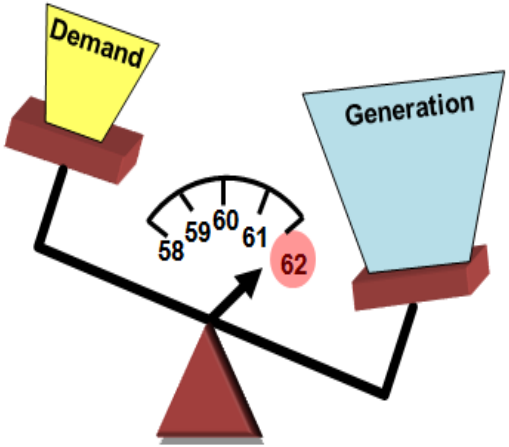
Ancillary Services

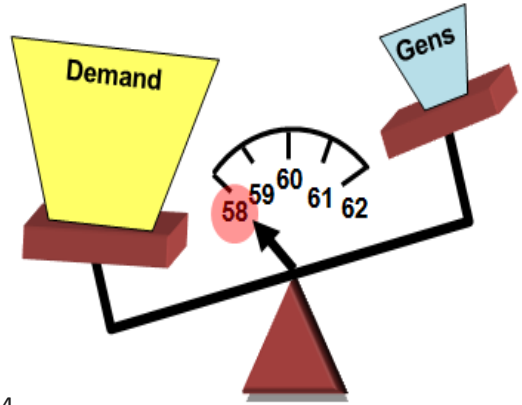
Regulation

Balancing Authority's Goal



Imbalance Conditions





Over-generation

- Total Generation > Total Demand
- Frequency > 60 Hertz
- Generators momentarily speed up

Under-generation

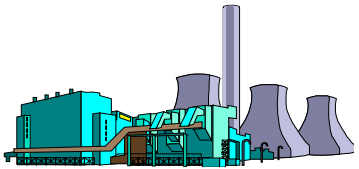
- Total Generation < Total Demand
- Frequency < 60 Hertz
- Generators momentarily slow down

What is Regulation?

Regulation is:

- A variable amount of generation energy under automatic control
- Independent of economic cost signal
- Obtainable within five minutes
- Responds to frequency deviations

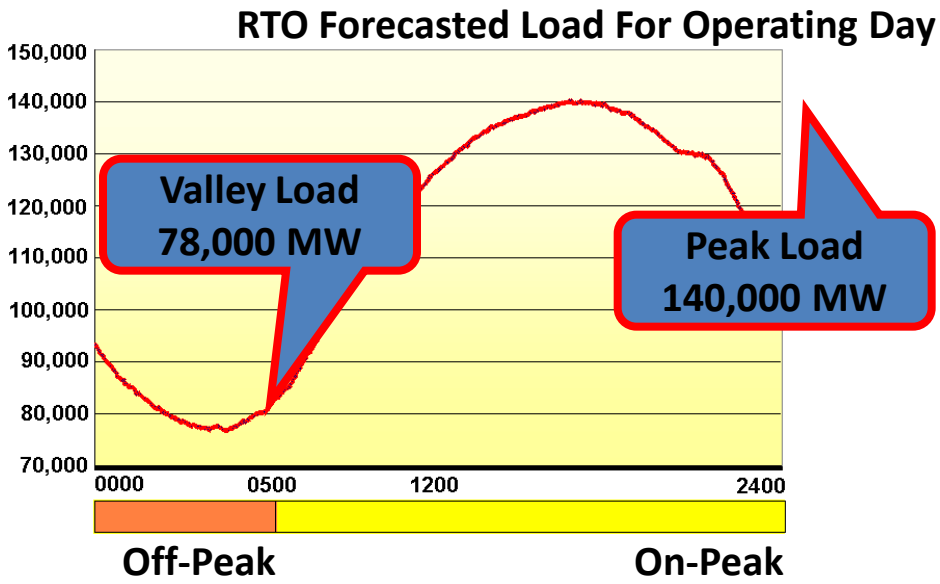
- These generating units or Demand Response Resources provide fine tuning that is necessary for effective system control
- Regulating units correct for small load changes that cause the power system to operate out of balance (measured as “ACE”)



PJM Market with Market-based Regulation

- Creates market for regulation
- Provides Market Clearing Prices for regulation
- Protects supplier by providing opportunity cost of energy
- Provides more incentive to provide regulation

PJM's Regulation Requirement (Example)



Off-Peak Regulation Requirement = 525 MW

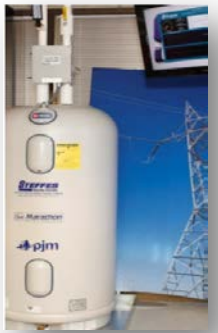
On-peak Regulation Requirement = 700 MW

Fulfilling Regulation Obligation

- All LSEs have hourly Regulation Obligation
  - pro rata share of PJM Regulation assigned for hour
    - based on LSE total real time hourly load
- Obligation can be satisfied by:
  - self-scheduling own resources
  - enter bilateral transactions with other participants
  - purchasing from PJM Regulation Market

Providing Wholesale Ancillary Services

- What types of Resource can provide regulation:
  - *Generation*: Steam, Hydroelectric, Combustion Turbines, Combined Cycle
  - *Grid Energy Storage*: Batteries, Flywheels
  - *Behind-the-meter Storage*: Water Heaters, Batteries, Plug-in Hybrid Electric Vehicles
  - *Demand Response*: Variable Speed Pumps, Ceramic Thermal Storage



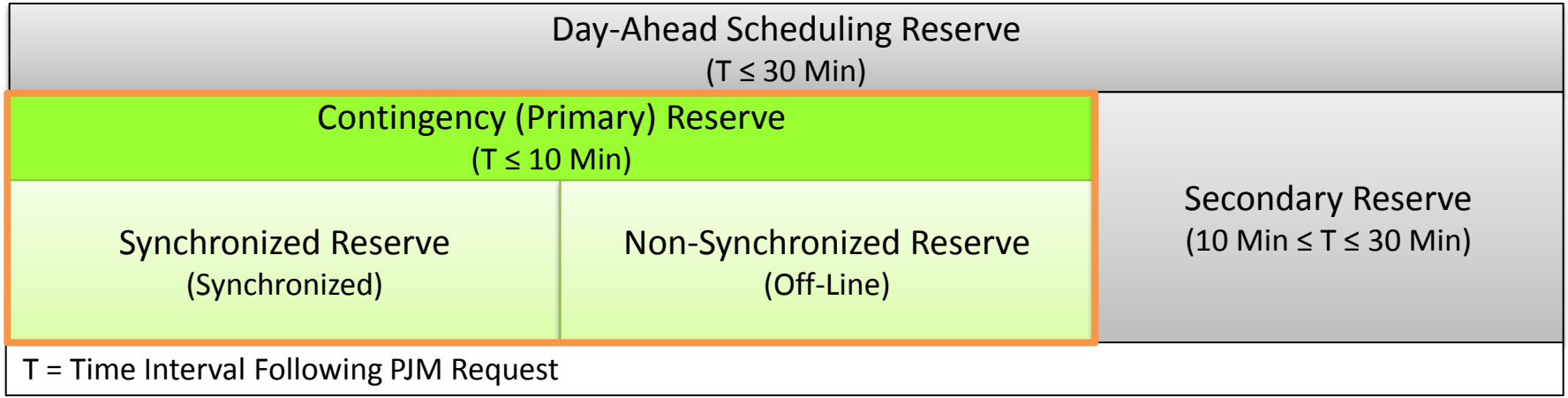
Characteristic Differences between Resources

- Ramp-Limited Resources
  - Examples include Steam, Combustion Turbine (CT), Combined Cycle (CC), Hydroelectric Dams
  - Fuel-burning results in hours of operation at all deployment levels (sustain full raise/lower)
  - Energy output rate-of-change limited by mechanical processes
  - Operates on Traditional Regulation Signal
- Energy-Limited Resources
  - Examples include Batteries and Flywheels
  - Sub-second matching of control signal (infinite ramp rate)
  - Energy output determined by state of charge, storage capacity
  - Operates on Dynamic Regulation Signal

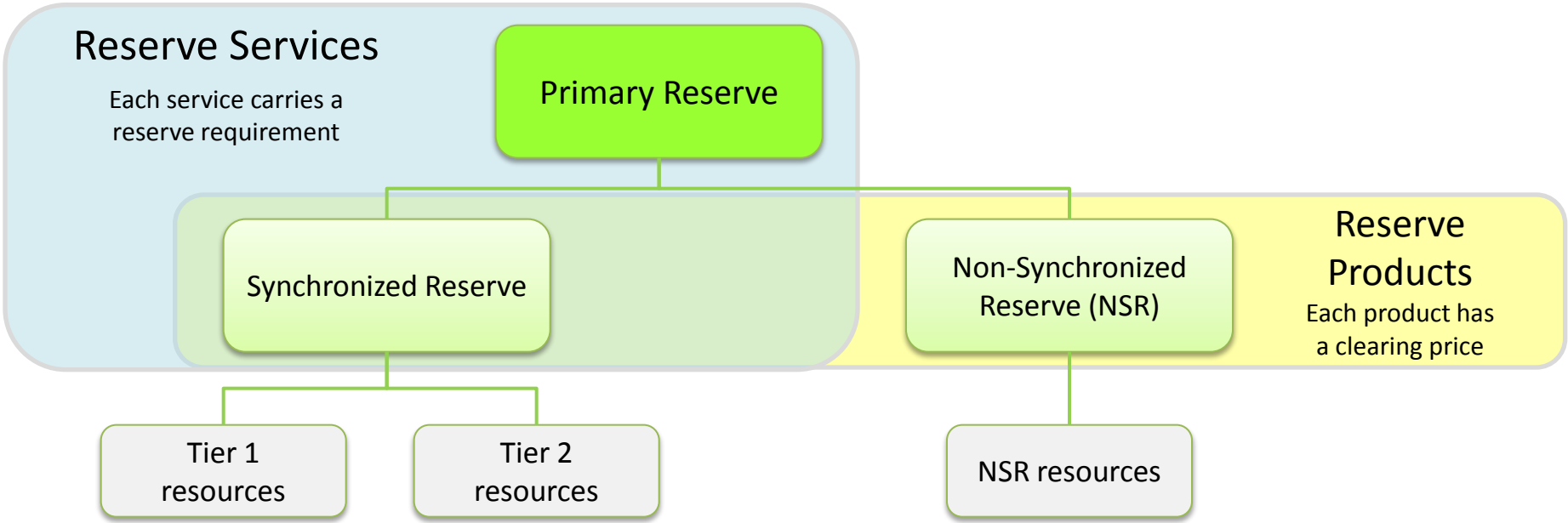
Reserves

Reserves

- Reserves are additional generation capacity above the expected load. Scheduling excess capacity protects the power system against the uncertain occurrence of future operating events, including the loss of energy or load forecasting errors



Reserve Markets



Primary Reserve Resource Types

Tier 1 (Economic)	Online units that are following economic dispatch and only partially loaded and therefore are able to increase output within 10 minutes following PJM dispatcher request to an event
Tier 2 (Non-Economic)	Resources that offered into the Synchronized Reserve Market and cleared • Condensers (CTs and hydro) transition to online Tier2 condense mode • Steam reduced to provide Tier2 MW, • CTs online at min – operating at a point that deviates from economic dispatch, • Demand Response that can drop load
10 minute Non-Synchronized Reserve	Resources currently not synchronized to the grid • Shutdown run-of-river hydro, • Shutdown pumped hydro, • Offline industrial combustion turbines, jet engine/expander turbines, etc

Synchronized Reserve Obligation

- Who must acquire Synchronized Reserves?
  - All load serving entities (LSEs)
  - Obligation determined from real time load ratio share
  - Obligation is by reserve zone

Non-Synch Reserve (NSR) Characteristics

- A resource will be considered eligible to provide NSR if it:
  - Is electrically located within the PJM RTO
  - Is available
  - Is not electrically synchronized to the grid
  - Can provide energy within 10 minutes of notification from PJM dispatch
  - Has not designated its entire output as emergency
  - Able to sustain output for 30 minutes

Non-Synchronized Reserve Obligation

- All load serving entities (LSEs) carry a Non-Synchronized Reserve obligation
- Obligation is determined based on:
  - Total NSR MW committed in the Non-Synchronized Reserve Market
  - LSE's real-time load ratio share
- Obligation is calculated by reserve zone

Fulfilling Obligation: Purchasing from Market

- Any obligation remaining will be fulfilled by purchasing from the market
- Non-Synchronized Reserves
- Loads located in the MAD sub-zone will pay the MAD NSRMCP
- Loads located outside the MAD sub-zone will pay the RTO NSRMCP
- Synchronized Reserves
- Loads located in the MAD sub-zone will pay the MAD SRMCP
- Loads located outside the MAD sub-zone will pay the RTO SRMCP

Reserve Markets and Product Substitution

- Synchronized Reserve Market
  - One market for each region if there are transmission constraints
  - Synchronized Reserves in MAD can be used to satisfy the RTO requirement (locational substitution)
  - Historically, very few hours when RTO Synch Reserve Market cleared with non-zero price
  - Price is always greater than or equal to the Non-Synchronized Reserve Price

- Non-Synchronized Reserve Market
  - Used to procure the balance of the Primary Reserve requirement that is not being met with Synch Reserve
  - Synch Reserve can be used in place of Non-Synch Reserve to meet the Primary Reserve requirement (product substitution)
  - Non-Synch Reserves in MAD can be used to satisfy the RTO Primary Reserve requirement (locational substitution)
  - Price is expected to be zero except when the system is getting shorter on reserves
  - Price is always less than or equal to the Synch Reserve price

Ancillary Services

Other Ancillary Services

Blackstart Service

Purpose: To provide a power source to start critical generation after a system shutdown

- Transmission Owners, with PJM identify critical Blackstart units
- Generator annual revenue requirements - Cost-based service
- Charges go to Transmission Customers
- Annual Blackstart testing requirements

Reactive Supply & Voltage Control

Purpose: To maintain transmission voltages within acceptable limits

- FERC approves reactive revenue requirements
- PJM calculates zonal rate
- Paid by transmission customers
- Credits go to generation resources and transmission owners

Scheduling, System Control & Dispatch

Purpose: To provide transmission service and operate the energy market

- Schedule 9 of PJM Tariff
  - Control Area Administrative Service
  - FTR Administrative Service
  - Market Support Service
  - Regulation Administrative Service
  - Capacity Resource and Obligation Service

Loss Allocation

Losses

- Transmission losses refer to the loss of energy in the transmission of electricity from generation resources to load, which is dissipated as heat through transformers, transmission lines, and other transmission facilities

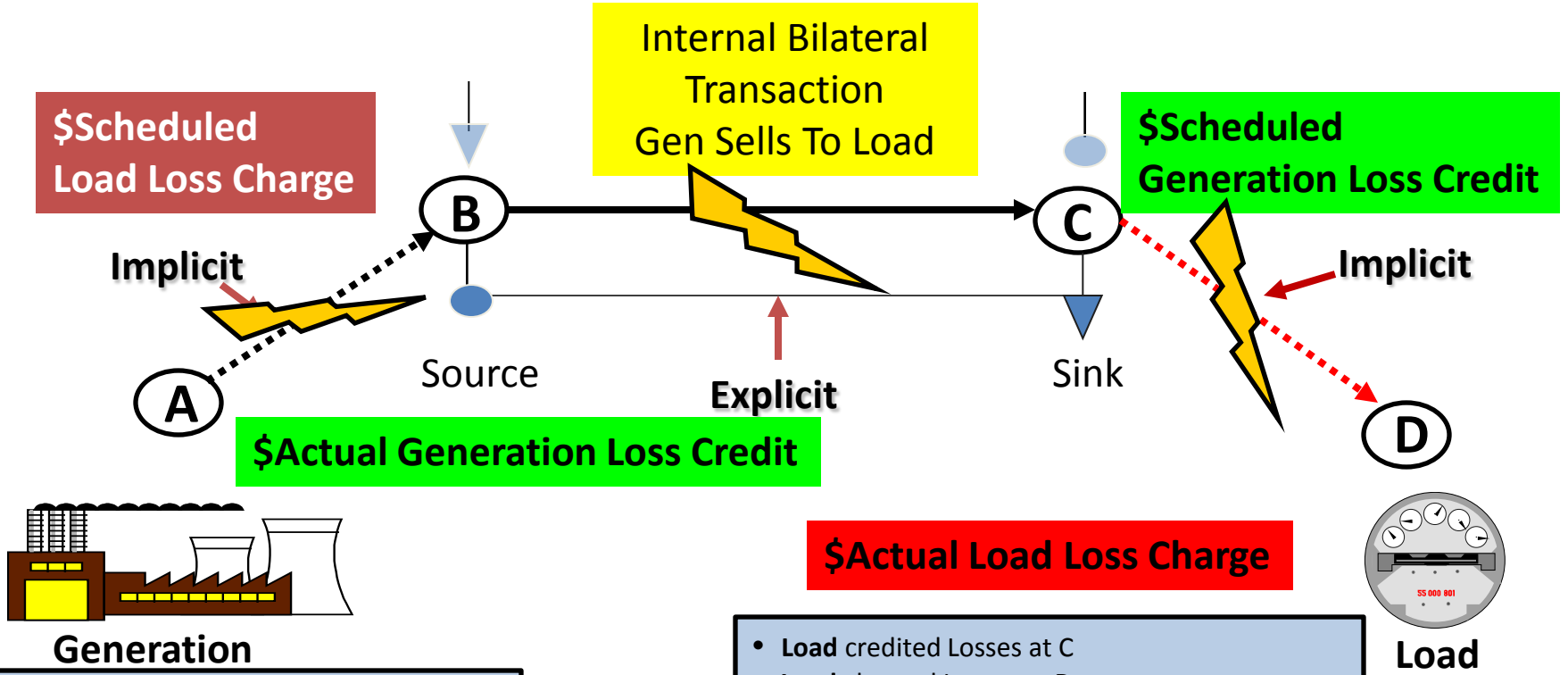
- Only the losses incurred on facilities included in the PJM network model and, therefore, reflected in the PJM State Estimator are included in the PJM settlements for transmission losses

Losses Billing

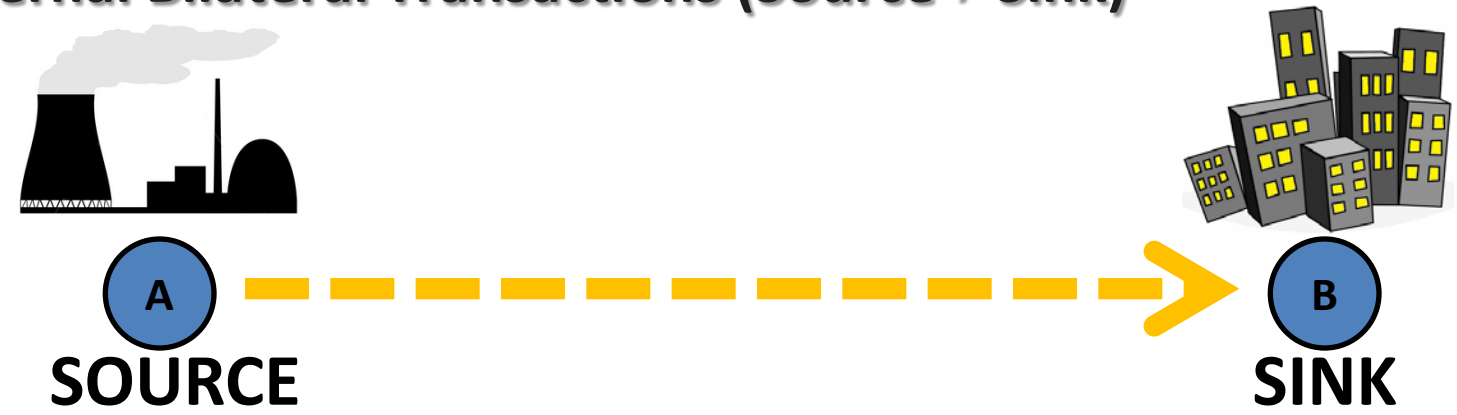
- Settlement for losses reflected in LMP calculation
- **Implicit Loss Charge**
  - Day-ahead and balancing locational net loss bill calculated hourly
    - Represents the marginal loss price difference between a participants injections and withdrawals
    - Calculated using the *Loss Price* component of LMP
- **Explicit Loss Charge**
  - Calculated using source and sink of transaction using *Loss Price* component of LMP

1220	Day-ahead Transmission Losses
1225	Balancing Transmission Losses

Loss Calculations



Internal Bilateral Transactions (Source ≠ Sink)



- Generator = Seller Load = Buyer

- Buyer pays explicit congestion and losses across the path (Sink – Source) B - A

- Generator credited implicit congestion and losses at the generator bus A
- Generator (as the seller) is charged implicit congestion and losses at the source A

- Load (as the buyer) is credited implicit congestion and losses at the sink B
- Load is charged implicit congestion and losses at the load bus B

Calculation of Locational Net Loss Bill (Implicit Losses)

Locational Net Loss Bill is the difference in Loss Price components of LMP between a participant's "load" and "generation"

Net Loss Bill (Implicit Loss Charge):
Load Loss Charges - Generation Loss Credits

Load Loss Charges*:

Load: Load Bus MWh x *Loss Price Component* of Load Bus LMP
Energy Sales: Sale MWh x *Loss Price Component* of Source LMP
Decrement Bids: Dec Bid MWh x *Loss Price Component* of Bus LMP

Generation Loss Credits*:

Generation: Generation Bus MWh x *Loss Price Component* of Generation Bus LMP
Energy Purchases: Purchase MWh x *Loss Price Component* of Sink LMP
Increment Offers: Inc Offer MWh x *Loss Price Component* of Bus LMP

** deviations are used for balancing market calculations*

Balancing Explicit Loss Charge

Real-time Transaction MWh – Day-ahead Transaction MWh *
(*Loss Price* Component of Real-time Sink LMP
Loss Price Component of Real-time Source LMP)

- Transmission customer pays losses for external transactions
- Buyer pays losses for internal transactions (network customer)
- Explicit loss charges are not included in the net loss bill calculations

MSRS - Transmission Loss Charge Summary

Transmission Loss Charge Summary															
Customer	PJM Interc	Report Creation	###########												
Start Date:	7/5/2012	End Date:	7/5/2012												
4000.01	4000.02	4000.05	4000.06	1220.16	1220.11	1220.17	1220.12	1220.01	1220.02	1225.18	1225.11	1225.19	1225.12	1225.01	1225.02
Customer	Customer	EPT Hour Ending	GMT Hour Ending	DA Loss Withdrawal Energy	DA Loss Withdrawal Charge ($)	DA Loss Injection Energy	DA Loss Injection Credit ($)	DA Implicit Loss Charge ($)	DA Explicit Loss Charge ($)	Bal Loss Withdrawal Energy	Bal Loss Withdrawal Charge ($)	Bal Loss Injection Energy	Bal Loss Injection Credit ($)	Bal Implicit Loss Charge ($)	Bal Explicit Loss Charge ($)
88888	DEK	07/05/2012 01	07/05/2012 05	0	0	150	16.5	-16.5	321.86	178.214167	326.13	100	33	293.13	-413.8
88888	DEK	07/05/2012 02	07/05/2012 06	0	0	300	-96	96	175.75	178.126667	244.03	50	20.5	223.53	-307.03
88888	DEK	07/05/2012 03	07/05/2012 07	0	0	350	10.5	-10.5	189.66	253.075333	117.33	0	0	117.33	-248.92
88888	DEK	07/05/2012 04	07/05/2012 08	0	0	350	-59.5	59.5	190.89	253.176833	105.7	0	0	105.7	-223.16
88888	DEK	07/05/2012 05	07/05/2012 09	0	0	350	70	-70	197.99	253.088167	102.62	0	0	102.62	-221.67

Data Granularity: Hourly

Frequency: Updated Daily

Supporting Calculations

DA Implicit Loss Charge (1220.01) = DA Loss Withdrawal Charge (1220.11) - DA Loss Injection Credit (1220.12)

Bal Implicit Loss Charge (1225.01) = Bal Loss Withdrawal Charge (1225.11) - Bal Loss Injection Credit (1225.12)

MSRS - Implicit Congestion and Loss Charge Details

Implicit Congestion and Loss Charge Details								
Customer Account:	PJM Interco	Report Creation Tir	10/9/2012 15:55					
Start Date:	2/5/2012	End Date:	2/5/2012					
4000.01	4000.02	4000.05	4000.06	4000.19	4000.2	3000.06	1210.14	1210.15
Customer ID	Customer C	EPT Hour Ending	GMT Hour Ending	PNODE Name	PNODE ID	PNODE DA Congestion Price ($/MWh)	DA Congestion Withdrawal Energy (MWh)	DA Congestion Injection Energy (MWh)
88888	DEK	02/05/2012 01	02/05/2012 05	DEK EXT LMP	99999999	-0.36	0	150
88888	DEK	02/05/2012 01	02/05/2012 05	DONEXT LMP	99999997	0	0	0
88888	DEK	02/05/2012 02	02/05/2012 06	DEK EXT LMP	99999999	-0.02	0	300
88888	DEK	02/05/2012 02	02/05/2012 06	DONEXT LMP	99999997	0	0	0
88888	DEK	02/05/2012 03	02/05/2012 07	DEK EXT LMP	99999999	-0.03	0	350
88888	DEK	02/05/2012 03	02/05/2012 07	DONEXT LMP	99999997	0	0	0
88888	DEK	02/05/2012 03	02/05/2012 07	OUTTHERE EXT	99999996	0	0	0

3000.15	1220.14	1220.15	3000.09	1215.14	1215.16	1215.15	1215.17
PNODE DA Loss Price ($/MWh)	DA Loss Withdrawal Energy (MWh)	DA Loss Injection Energy (MWh)	PNODE RT Congestion Price ($/MWh)	RT Congestion Withdrawal Energy (MWh)	Bal Congestion Withdrawal Energy Deviation (MWh)	RT Congestion Injection Energy (MWh)	Bal Congestion Injection Energy Deviation (MWh)
0.11	0	150	-0.45	0	0	250	100
0	0	0	-0.12	178.214167	178.21	0	0
-0.32	0	300	-0.48	0	0	350	50
0	0	0	-0.82	178.126667	178.13	0	0
0.03	0	350	-0.41	0	0	350	0
0	0	0	-0.88	178.075333	178.08	0	0
0	0	0	-12.88	75	75	0	0

3000.18	1225.14	1225.15	1225.16	1225.17
PNODE RT Loss Price ($/MWh)	RT Loss Withdrawal Energy (MWh)	Bal Loss Withdrawal Energy Deviation (MWh)	RT Loss Injection Energy (MWh)	Bal Loss Injection Energy Deviation (MWh)
0.33	0	0	250	100
1.83	178.214167	178.21	0	0
0.41	0	0	350	50
1.37	178.126667	178.13	0	0
0.46	0	0	350	0
1	178.075333	178.08	0	0
-0.81	75	75	0	0

MSRS - Explicit Loss Charges

	A	B	C	D	E	F	G	H	I	J	K	L	M
1	Explicit Loss Charges												
2	Customer	PJM Interc	Report Creation	##########									
3	Start Date	1/31/2008	End Date:	1/31/2008									
4	4000.01	4000.02	4000.05	4000.06	4000.09	4000.13	4000.1	4000.17	4000.18	4000.2	4000.22	4000.2	4000.24
5	Customer ID	Customer Code	EPT Hour Ending	GMT Hour Ending	Transaction ID	NERC Tag	OASIS ID	Buyer	Seller	Sink PNODE Name	Sink PNODE ID	Source PNODE Name	Source PNODE ID
6	1234	PALCO	01/31/2008 01	01/31/2008 06	MECS56814	PJM_PALCO12345678_MISO	123456	MECSCA	PALCO	MISO	40523629	PPL	51299
7	1234	PALCO	01/31/2008 01	01/31/2008 06	NYIS246152	NYIS_PALCO87654321_PJM	654321	PALCO	NYISO	PECO	51297	NYIS	5413134

	M	N	O	P	Q	R	S	T	U	V	W
1											
2											
3											
4	4000.24	3000.72	3000.16	3000.17	1220.13	3000.73	3000.74	3000.19	3000.2	1225.13	4000.07
5	Source PNODE ID	DA Transaction MWh	DA Sink Loss Price ($/MWh)	DA Source Loss Price ($/MWh)	DA Explicit Loss Charge ($)	RT Transaction MWh	Transaction Deviation (MWh)	RT Sink Loss Price ($/MWh)	RT Source Loss Price ($/MWh)	Bal Explicit Loss Charge ($)	Version
6	51299	0			0	48	48	-1.6	0.739207	-112.28	20080101
7	5413134	40	0.8	0.75	2	50	10	1.01	0.739207	2.70793	20080101

9 Supporting Calculations

DA Explicit Loss Charge (1220.13) = DA Transaction MWh (3000.72) * (DA Sink Loss Price (3000.16) - DA Source Loss Price (3000.17))

Bal Transaction Deviation (3000.74) = RT Transaction MWh (3000.73) - DA Transaction MWh (3000.72)

Bal Explicit Loss Charge (1225.13) = Bal Transaction Deviation (3000.74) * (RT Sink Loss Price (3000.19) - RT Source Loss Price (3000.20))

MSRS - Transmission Loss Credit Summary

	A	B	C	D	E	F	G	H	I	J	K	L	M
1	Transmission Loss Credit Summary												
2	Customer Ac	PJM Interc	Report Creatio	##########									
3	Start Date:	########	End Date:	10/10/2010									
4	4000.01	4000.02	4000.05	4000.06	2220.11	3000.38	2220.13	2220.14	2220.15	2220.16	2220.17	2220.01	4000.07
5	Customer ID	Customer Code	EPT Hour Ending	GMT Hour Ending	Total PJM Loss Revenues ($)	RT Load (MWh)	Firm RT Exports (MWh)	Non-Firm RT Exports (MWh)	Non-Firm Reduction Factor	Reduced Non-Firm Exports (MWh)	Total PJM RT Load plus Reduced Exports (MWh)	Transmission Loss Credit ($)	Version
6	1234	PALCO	10/01/2010 23	10/02/2010 03	48135.28	0	0	100	0.31	31	66561.903	22.42	20101001
7	1234	PALCO	10/01/2010 24	10/02/2010 04	43544.61	0	0	100	0.31	31	61981.838	21.78	20101001
8	End of Report												

Supporting Calculations

Transmission Loss Credit (2220.01) = Total PJM Loss Revenues (2220.11) * ((RT Load (3000.38) + Firm RT Exports (2220.13) + Reduced Non-Firm Exports (2220.16)) / Total PJM RT Load plus Reduced Exports (2220.17))

Demand Response

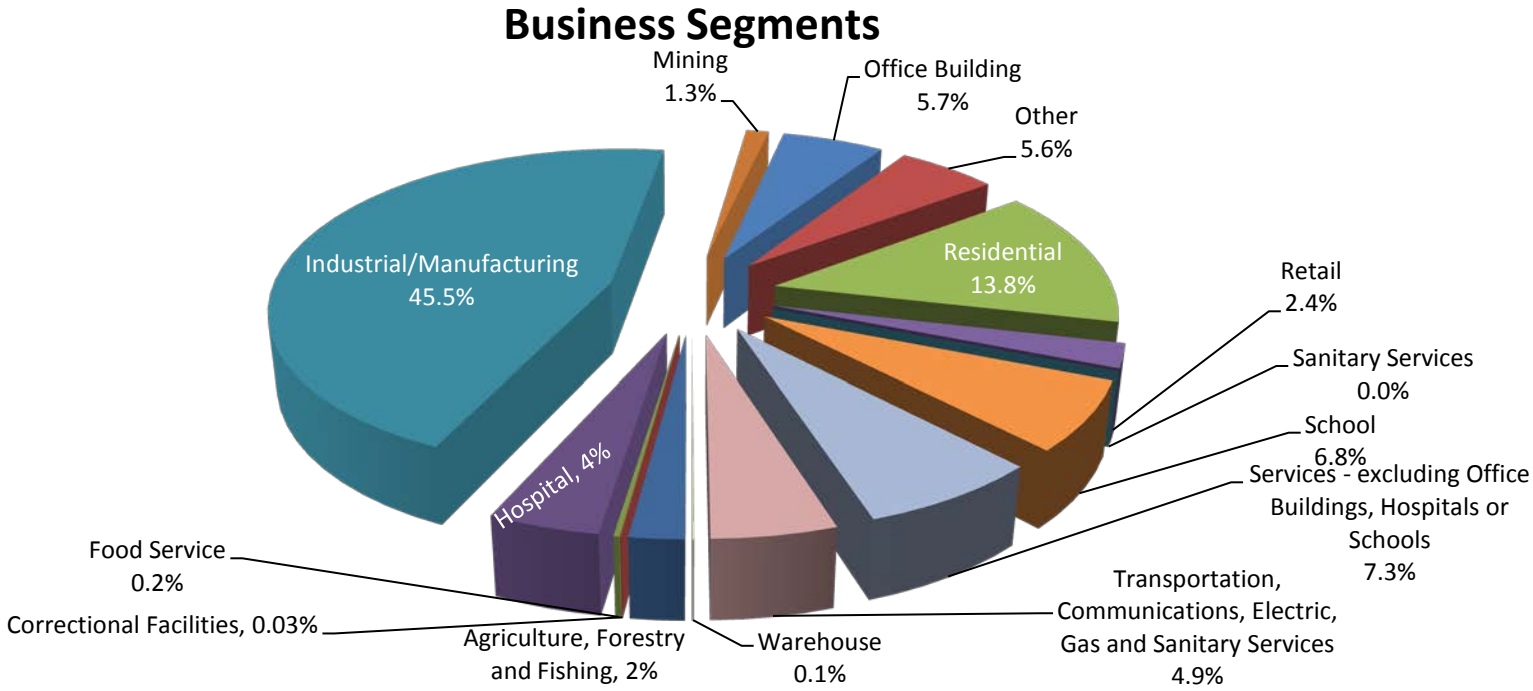
PJM Demand Response

- The purpose of PJM Demand Response is to enable Demand Resources under the direction and control of Curtailment Service Providers to respond to economic prices
- Demand Response can participate within the various PJM markets:
- Energy
  - Day Ahead
  - Real Time
    - Dispatched
- Ancillary Services
  - Synchronized Reserve
  - Day Ahead Scheduling Reserve
  - Regulation
- Capacity
  - Offer into auction up to 3 years in advance

Delivery Year 2013-2014 Active Participants in PJM Load Response Program as of 5/7/2013

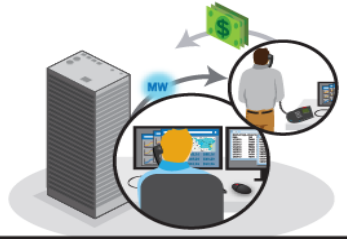
- Economic Sites: 1,450
- Economic MW: 2,200
- Emergency DR Sites: 10,992
- Emergency DR MW: 7,346

Business Segments for Emergency DR Activity 13/14



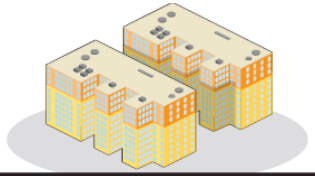
Note: data reported by CSPs having confirmed Load Management resources for DY 2013/2014

PJM Market Participants in Demand Response



Load Serving Entity (LSE)

PJM Member, including load aggregator or power marketer, that serves end-users in PJM Control Area to sell electric energy to end-users in PJM Control Areas.

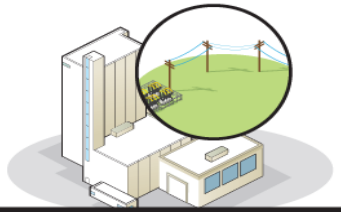


End Use Customer

Cannot directly participate unless it is a PJM Member (e.g. as an LSE or CSP).

Curtailment Service Provider (CSP)

PJM Members that act on behalf of end-use customers who wish to participate in PJM Load Response opportunities.



Electric Distribution Company (EDC)

PJM Member that owns, or leases, electric distribution facilities used to provide electric distribution service to electric load in PJM Control Areas.

Who can be a CSP?

- **Any LSE**
- **Any EDC**
- **Any third party** *(PJM member)* **specializing in Demand Response**

Business Rules - Economic

- The intent of Economic DR is for participants to *respond to price (RT and DA LMP)*
- End Use customers must have interval meters
- Exception for Direct Load Control
- Customer or CSP can provide interval meter provided it meets the PJM criteria
- The CSP, EDC, LSE, PJM and the PJM Market Monitor will monitor DR market behavior
  - Registration & Settlement issues

PJM Demand Response

- Like a generator, a DR resource participates in the Day Ahead and Real-Time energy markets

- Unlike a generator that is a capacity resource, DR participation in the energy market is voluntary

Questions?

Disclaimer:

PJM has made all efforts possible to accurately document all information in this presentation. The information seen here does not supersede the PJM Operating Agreement or the PJM Tariff both of which can be found by accessing: http://www.pjm.com/documents/agreements/pjm-agreements.aspx

For additional detailed information on any of the topics discussed, please refer to the appropriate PJM manual which can be found by accessing: http://www.pjm.com/documents/manuals.aspx