Louisiana Public Service Commission (LPSC)

Technical Conference

July 29, 2014

(Revised)

Technical Conference Agenda

- Locational Marginal Price (LMP)
- Auction Revenue Rights (ARR) and Financial Transmission Rights (FTR)
- Resource Adequacy
- Transmission Planning
- Communications for Emergency Conditions
- Value Proposition

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- **Locational Marginal Price (LMP)**
- Auction Revenue Rights (ARR) and Financial Transmission Rights (FTR)
- Resource Adequacy
- Transmission Planning
- Communications for Emergency Conditions
- Value Proposition

Market Design

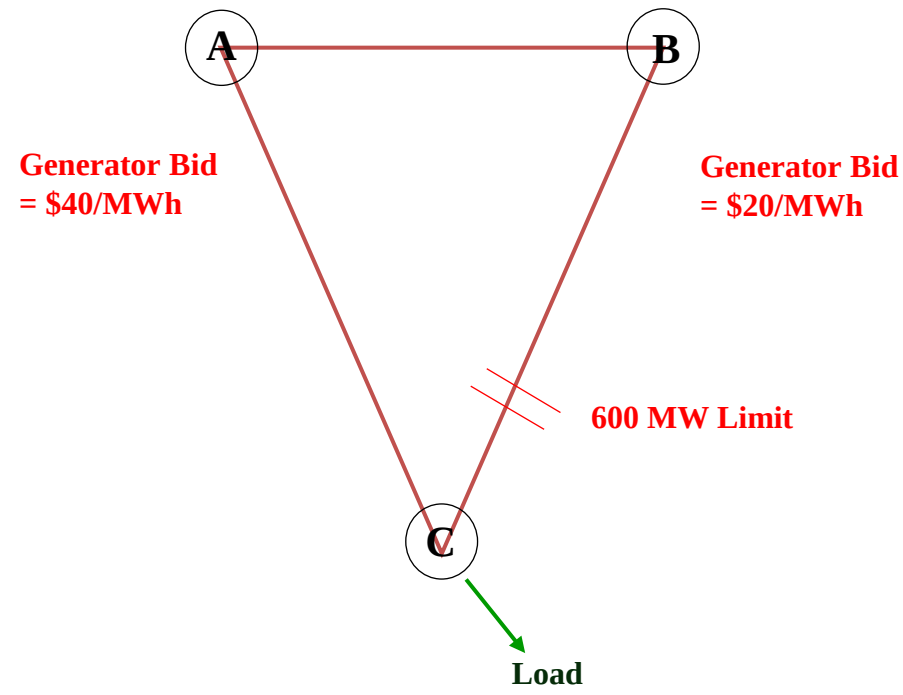
- Centralized dispatch = real time market.
  - Dispatch based on “Locational Marginal Pricing” (LMP).
- LMP is an approach to running a real-time energy market and pricing system that overcomes the limitations inherent in physical rights systems (i.e. TLR based systems)
- There are three primary elements of an LMP system:
  - Uses security constrained economic (re)dispatch based on market participant offers.
  - Calculates market prices (LMPs) from this dispatch and uses them for energy market settlements.
  - Provides redispatch and balancing market services to anyone willing to pay the energy market/redispatch prices.

What is LMP?

- A “tool” for coordinating power flows.
  - Relies on price signals to “direct” generator output.
- In its simplest form nodal pricing:
  - Is the “cost” of electricity at the generator bus and the cost of moving the electricity from the generator to the consumer.
- Nodal pricing is based on the notion that *place* and *time* are important characteristics of electricity.
  - In essence, energy delivered to a different place and/or at a different time is a different good and should be priced accordingly in order to achieve economic efficiency.
- Recognizes the effects of joint production of energy for delivery and energy for consumption.
- *NOT NEW. Utilities have been doing economic dispatch for years!*

Example of Dispatch and Price Calculation

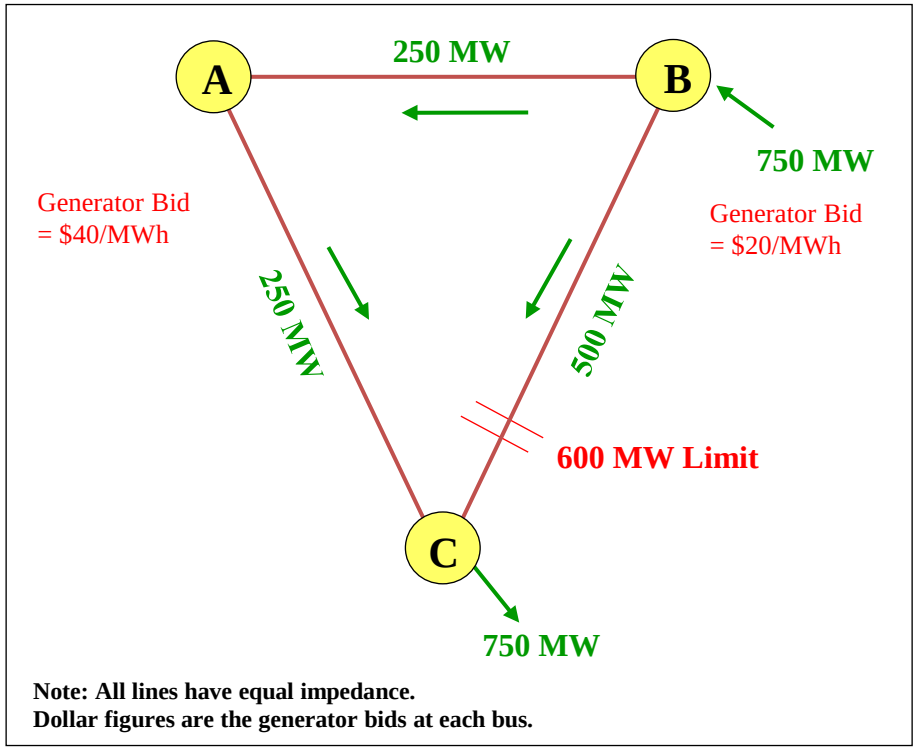
- The following example illustrates how LMP prices are calculated from the security-constrained dispatch of a simple transmission system, given the market participant's bids.



Note: All lines have equal impedance.
Dollar figures are the generator bids at each bus.

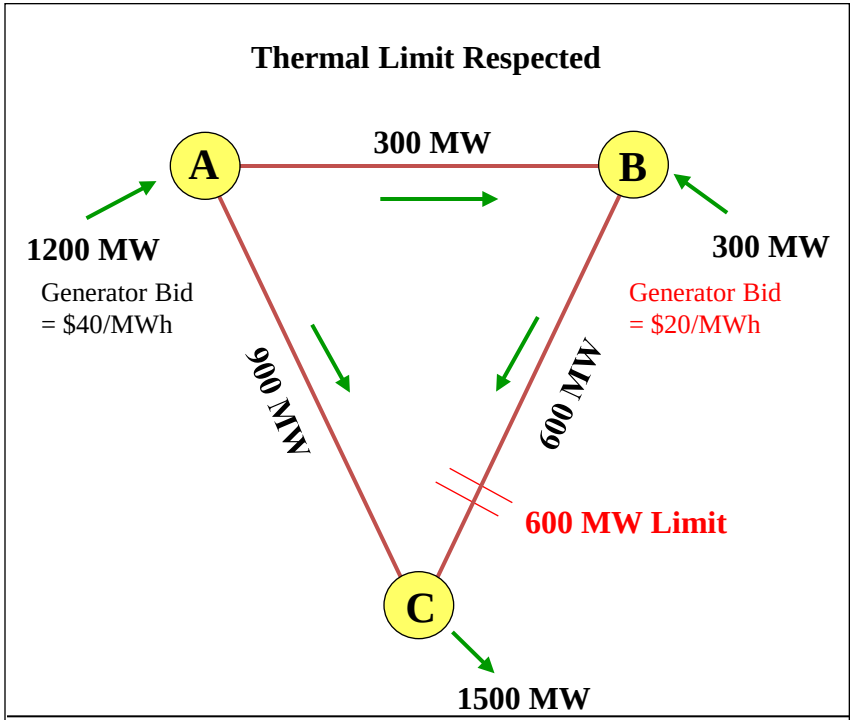
Unconstrained Least Offer Cost Dispatch

- If the load on this system were 750 MW at C, it could all be met with the $20/MWh generator at B.
  - Flow on the line BC is 500 MW, below the 600 MW limit, because not all of the energy injected at B flows to C on the BC line.
  - There is no transmission congestion.

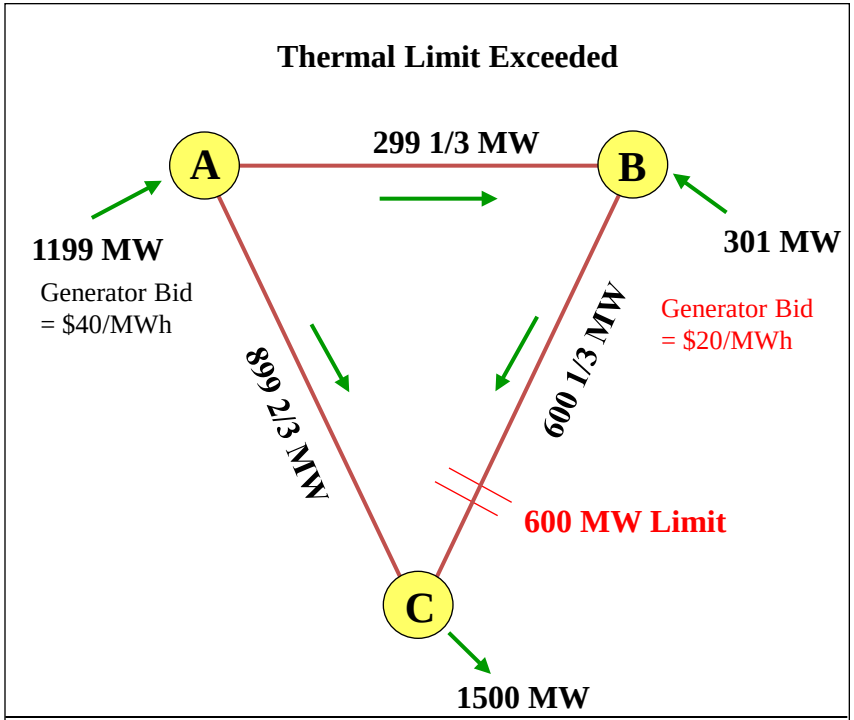


Constrained Least Offer Cost Dispatch

- If load at C increased to 1,500 MW, however, then it could not be met exclusively with the low bid generation at B without exceeding the limit on the line BC. At most 300 MW can come from B.



A to B Flow = 400 from gen A - 100 from gen B = 300 MW
A to C Flow = 800 from gen A + 100 from gen B = 900 MW
B to C Flow = 400 from gen A + 200 from gen B = 600 MW



- A to B Flow = -1/3 from gen A - 1/3 from gen B = -2/3 MW
- A to C Flow = -2/3 from gen A + 1/3 from gen B = -1/3 MW
- B to C Flow = -1/3 from gen A + 2/3 from gen B = 1/3 MW

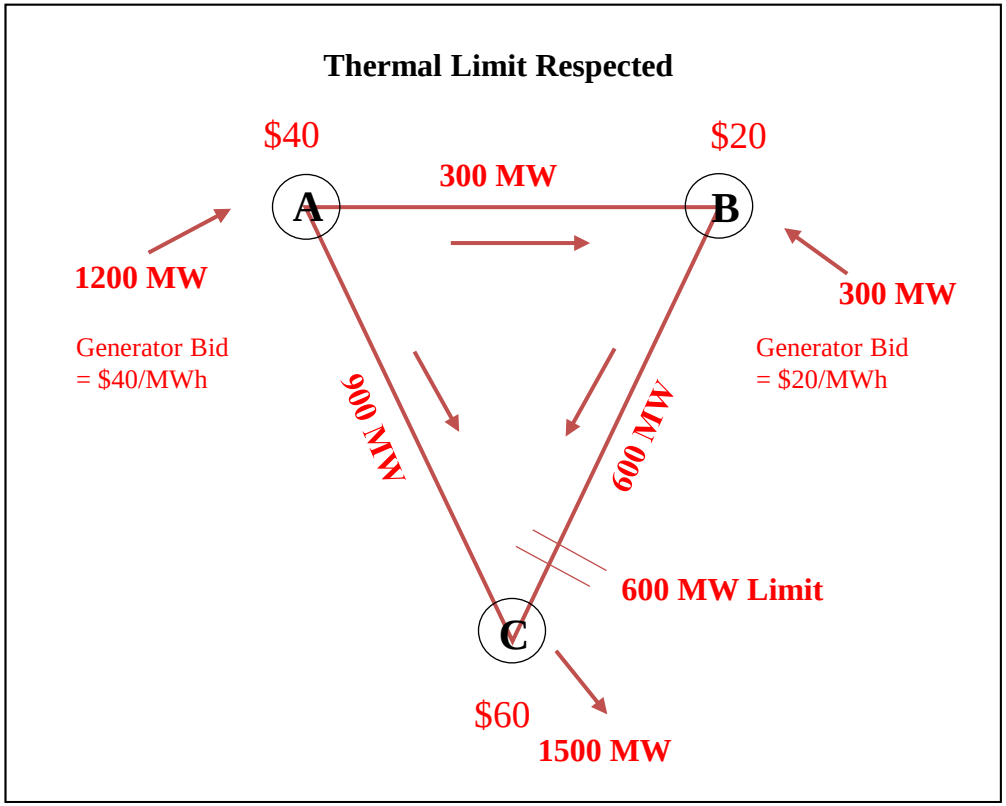
Note: All lines have equal impedance. Dollar figures are the generator offers at each bus.

Constrained Least Cost Dispatch

- When there is transmission congestion:
  - The least-cost (based on offers) mix of bidding generators cannot be used to meet load.
  - Out of merit redispatch of more than one generator is necessary to serve an increment of load at C.
  - Small increases in injections at some locations (B) rather than at other locations (A) would cause a transmission limit to be exceeded.
- The market value of incremental generation at location B must be less than at locations A and C.
- Not all “requests” for transmission to serve load at C from location B can be accommodated.

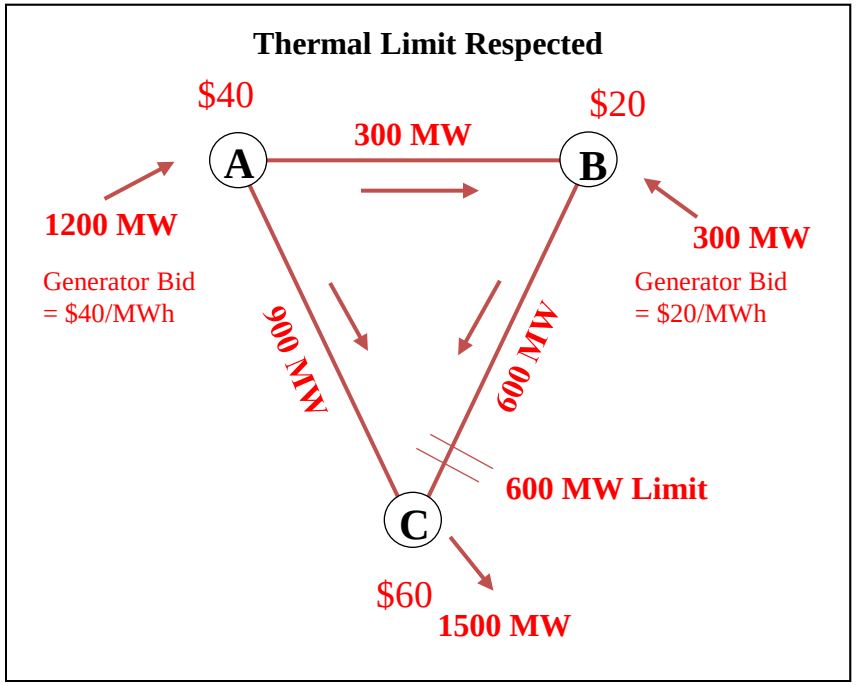
Price Derivation

- The LMP is the lowest (re)dispatch cost (based on bids from generators) of supplying energy to the next increment of load at a specific location on the transmission grid, while observing all security limits.



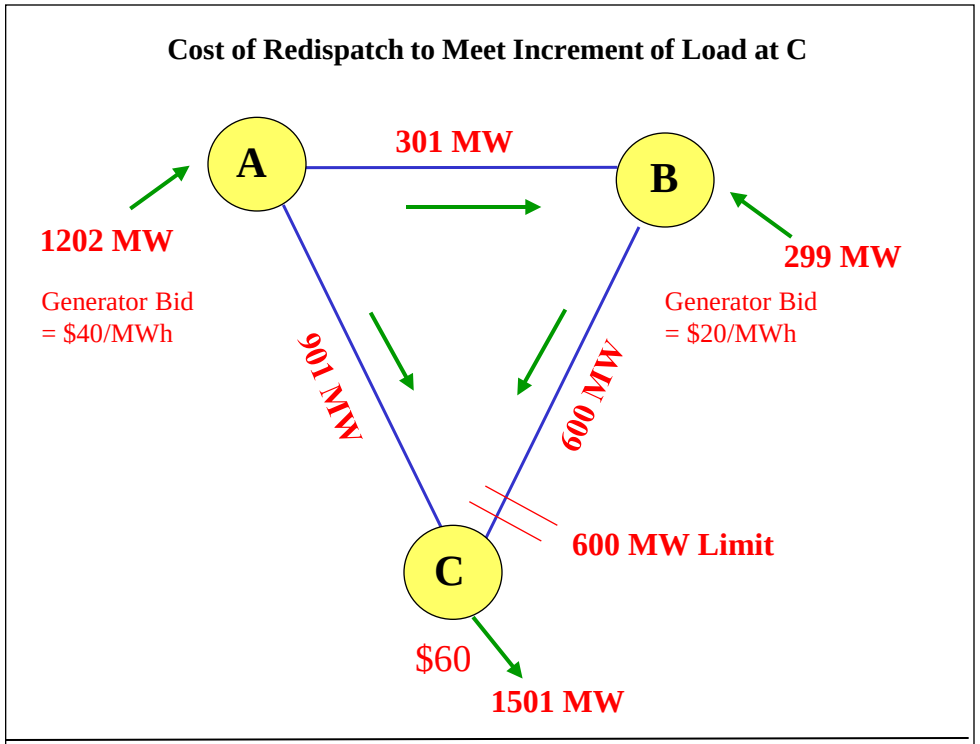
Price Derivation at Locations A & B

- The LMP at B is $20/MWh. An increment of load at B can be met at lowest bid cost by dispatching the generator at B at a price of $20.
- The LMP at A is $40/MWh. An increment of load at A can be met at lowest bid cost by dispatching the generator at A at a price of $40. Incremental generation at B cannot serve load at A, because part of it would flow on the line from B to C, violating the limit on this line.



Price Derivation at Location C

- The $60 LMP at location C occurs because the least-cost (re)dispatch to meet an increment of load there, while meeting the thermal limit, is to increase generation by 2 MW at node A and to decrease it by 1 MW at node B (2MW *$40 – 1MW * $20 = $60).



Δ B to C Flow = 2/3 from gen A - 2/3 from gen B = 0 MW

Price Derivation Summary

- Based on actual flow of energy
- Based on the actual system operating conditions
- When the transmission system is unconstrained, LMPs are equal at all locations
  - *If losses are included then LMPs will vary even if system is unconstrained.*
- Under constrained conditions, LMPs vary by location

Settlements

- Under an LMP system:
  - Generators are paid the LMP at their transmission bus for balancing energy.
  - LSEs pay the LMP at their location (node or zone) for schedule imbalances.
  - Transmission users pay transmission congestion charges. The transmission congestion charge is the difference between the LMP at the withdrawal location for the transaction less the LMP at the injection location. This is the lowest cost redispatch (based on bids) that reliably accommodates the transaction, on margin.
  - LMPw - LMPi = Congestion Charge

Load Settlement Zone Definition

- Definition of load zones: Load zones establish pricing points upon which the LSE will be charged
  - LSEs in MISO voluntarily define their load zones based on the actual metered withdrawal points of their customers
  - If broader pricing zones were established across multiple LSEs
    - This would serve to mute the price signal these MPs face, and therefore, inhibit demand response
  - Locational pricing and time-differentiated pricing

Settlement Prices Consistent with Reliability

- A key characteristic of LMP is that the prices used for balancing market settlements fully reflect the impact of congestion on:
  - The value of incremental generation at different locations.
  - The bid-based cost of serving incremental load at different locations.
  - The bid-based cost of the redispatch required to reliably accommodate an incremental transaction between two locations
- Using LMP for balancing market settlements provides incentives for market participants to make voluntary decisions that are consistent with maintaining reliability. Thus, LMP is a way to use market prices, rather than administrative restrictions and balancing penalties, to manage transmission congestion and maintain reliability.

Generation Settlement - Simple Case

- Under an LMP system:
  - Generators are paid the LMP at their transmission bus for balancing energy.
    - Thus the generator at A (Ga) will get paid - **from the pool:**
      - $40 * 1200 MW = $48,000
    - The generator at B (Gb) will get paid - **from the pool:**
      - $20 * 300 MW = $6,000
    - Total dollars paid **from the pool** to generators = $54,000

Load Settlement - Simple Case

- Under an LMP system:
  - LSEs pay the LMP at their location (node or zone).
    - Total dollars paid **to the pool** by load, $60 * 1500 = $90,000.
- Whenever there is a transmission constraint (or if losses are included in the price determination), the RTO will over collect.
  - In this example, generators received $54,000 and load paid $90,000…$36,000
  - **What happens to this money?**
  - **It is returned to the participants!**
    - Financial transmission rights (FTRs, TCCs, CRRs)

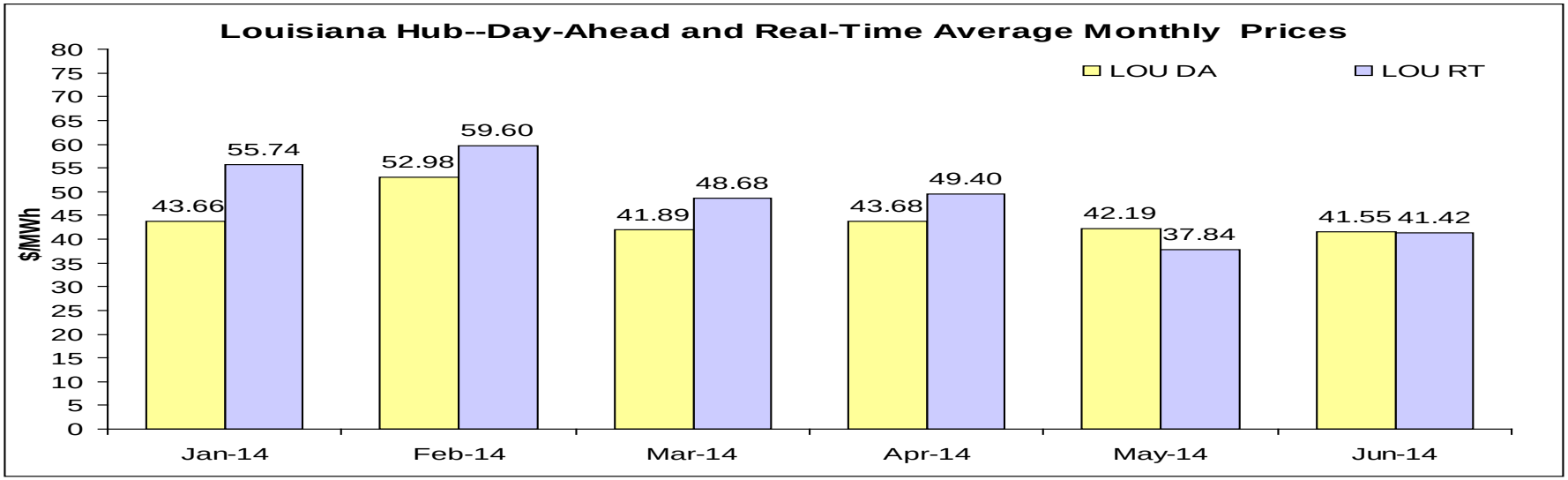
Settlement with a Bilateral Contract

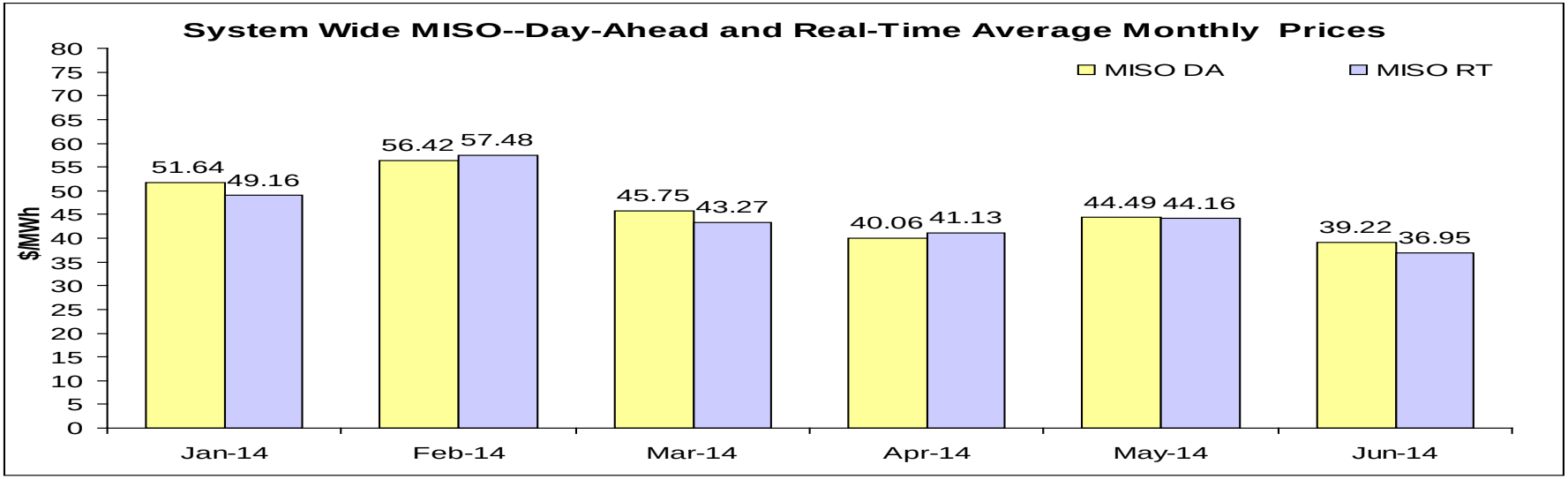
- Suppose that Ga and the load at C had a bilateral contract for 400MW at $30/MW – how would that settle?
  - The 400MW would not transact at LMP. Whoever submits the "schedule" pays the congestion costs.
  - Payments to generators would be:
    - Gb: $20 * 300 MW = $6000
    - Ga: $40 * 800 MW = $32,000
    - Total = $38,000
  - Payments from load would be:
    - Load at C: $60 * 1100 MW = $66,000
    - Schedule C-A: $20 * 400 MW = $8,000
    - Total = $74,000
  - Excess collection = $36,000 *exactly the same as before!*
- As the market matures, these contracts will take the form of a "CfD' or Contract for Difference rather than "physical" bilaterals.

LMP Market Overview

- MISO operates energy markets to develop day-ahead transmission schedules and to dispatch generation in real-time to manage congestion and schedule imbalances
- Markets are based on centralized dispatch, using a Locational Marginal Pricing (LMP) method
  - LMP at a bus or a defined aggregated set of buses is a single price (disaggregated into three components - energy, congestion, and losses) reflecting the marginal cost of serving the next increment of load at that location
- Market Participants may acquire Financial Transmission Rights (FTRs) to hedge potential Day Ahead LMP congestion differences.
- Market Participants receive settlement statements based upon their position in each of the MISO administered markets

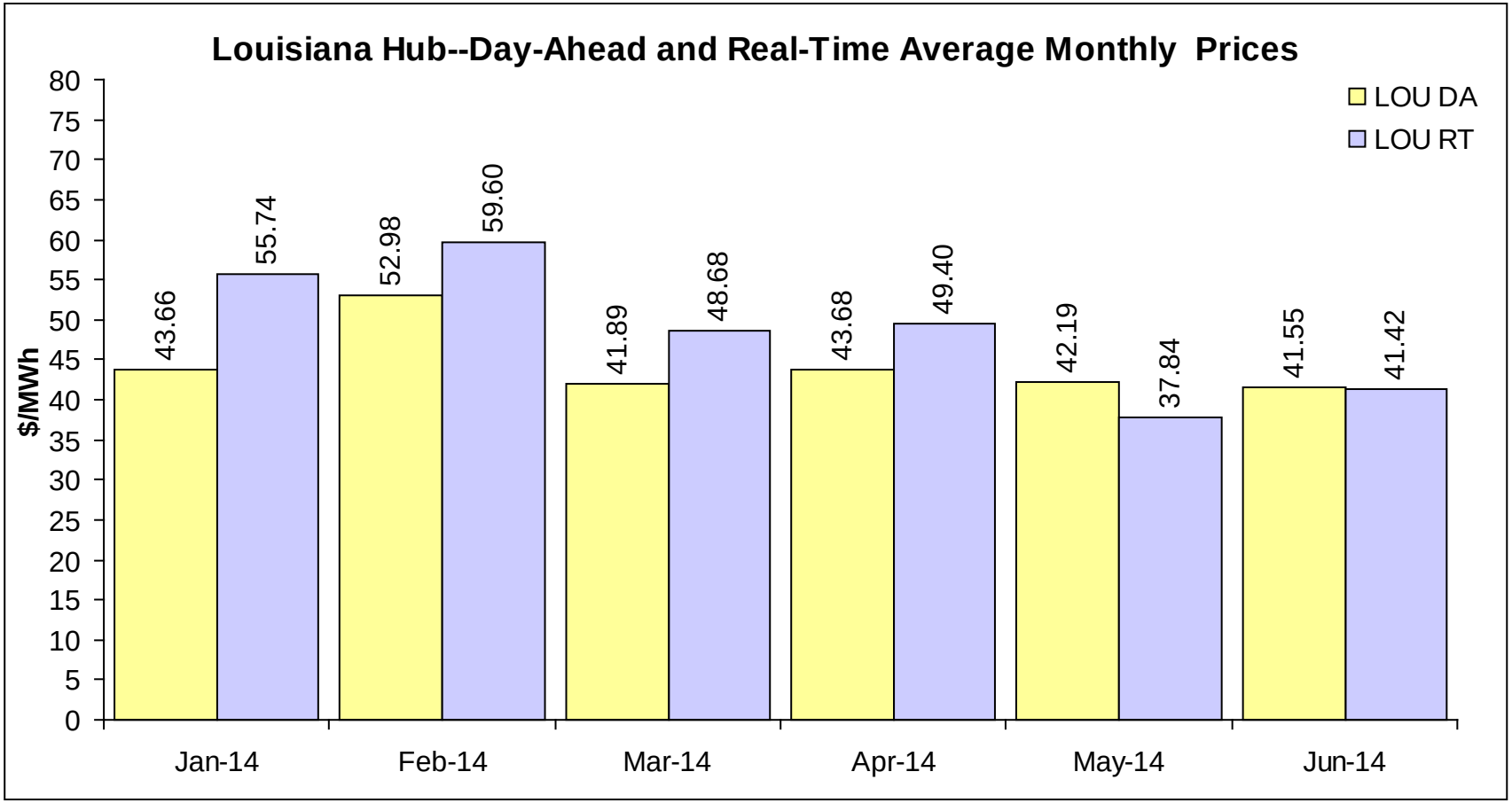
Market Analysis for Louisiana Hub





Source: MISO Information Delivery and Market Analysis Department

Pricing



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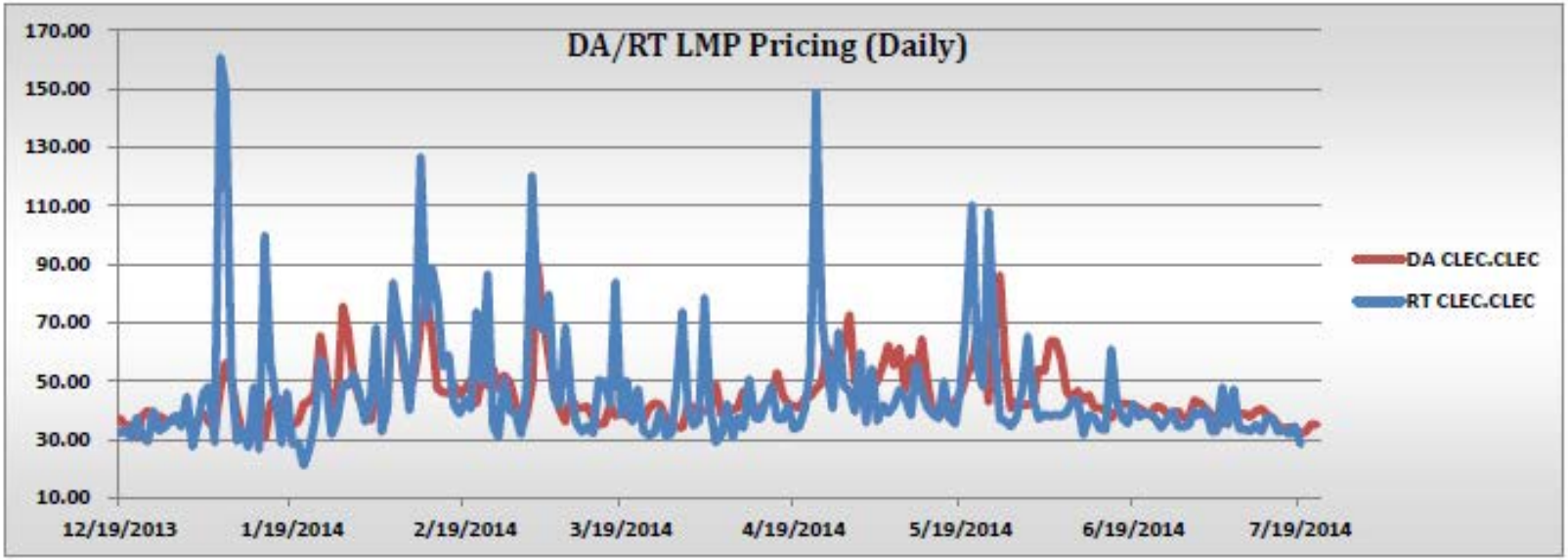
DA/RT LMP Pricing (Daily)
170.00
150.00
130.00
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90.00
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12/19/2013
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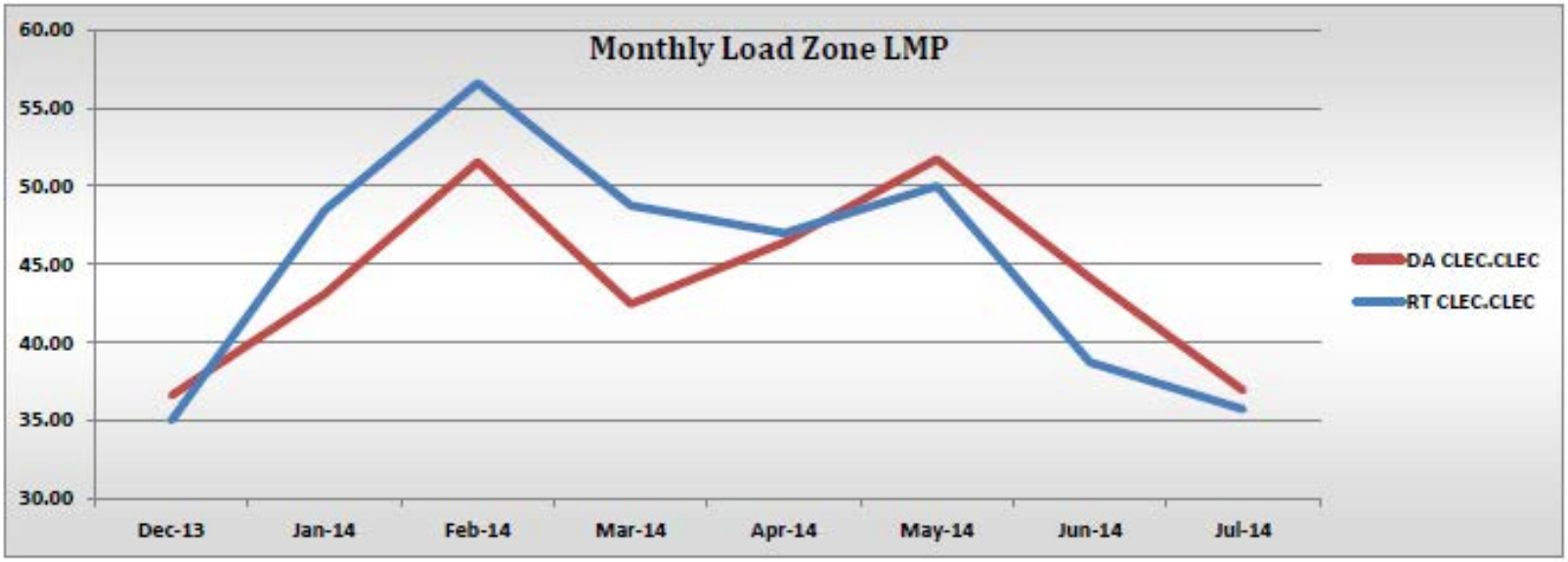
Monthly Load Zone LMP
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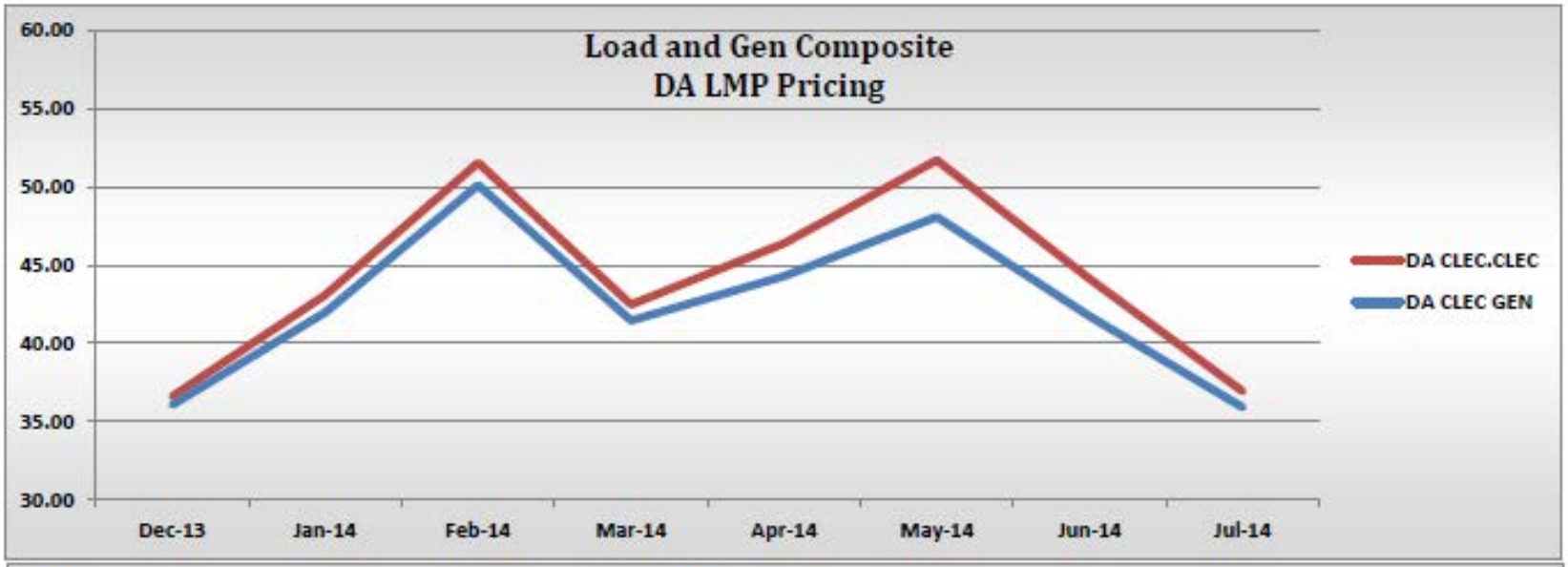
CLECO


Load and Gen Composite
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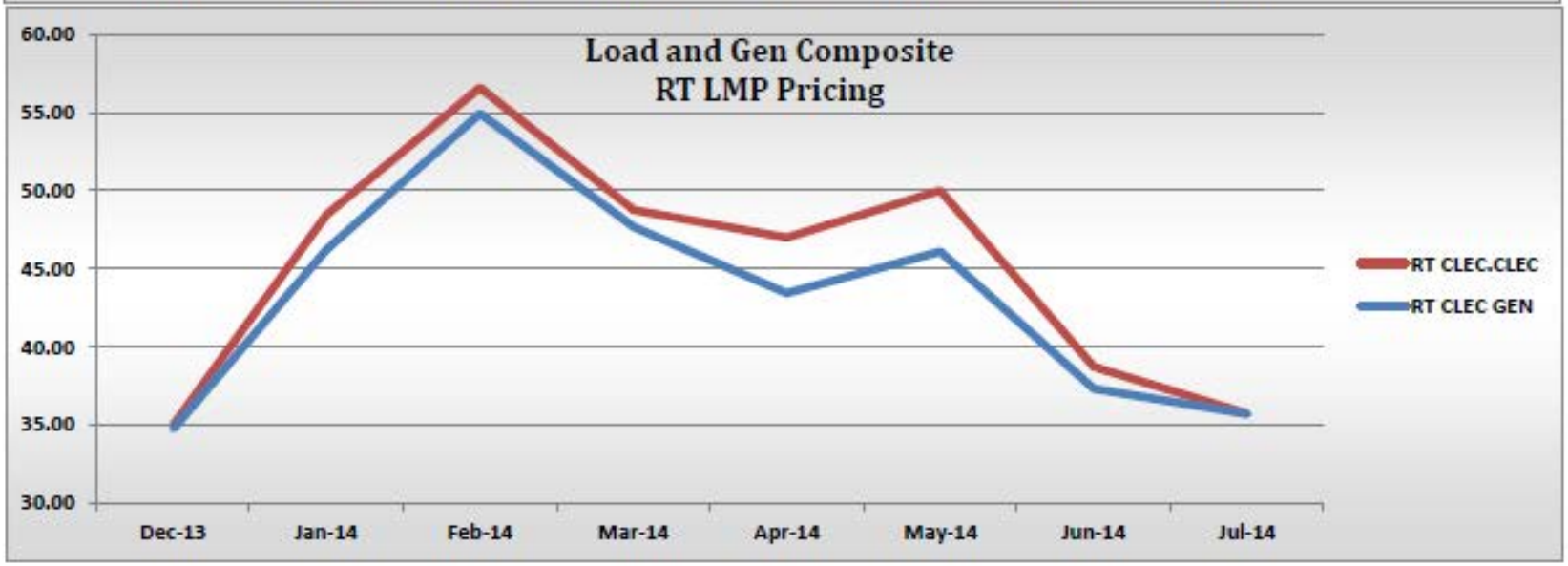
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RT CLEC.CLEC
RT CLEC GEN

CLECO

Retail Rates Do Not Equal LMPs

- Customers pay fuel cost of OpCo generation plus net MISO bill (adjusted by System Agreement accounting as applicable).
- OpCo's generation and OpCo's FTRs hedge customers against LMPs.
  - As will be explained in later slides, the Companies' FTRs have proven to be an effective hedge against congestion, and the effectiveness of that hedge is expected to continue.
- Major components of net MISO bill for an OpCo:
  - Revenues from MISO for sale of owned and contracted generation (at generator bus LMPs)
  - Minus charges from MISO for purchases for loads (at load zone LMP)
  - Plus net revenues from MISO for the OpCo's FTRs (based on difference between generator bus LMP and load zone LMP)
  - Plus net revenues (costs) from MISO for uplift

LMP v. Cost to Serve Load – Example

- If an OpCo has an FTR from its generator, its cost to serve load from that generator will be identical to its pre-MISO cost.

Assumptions:	Cost of service Pre-MISO			Cost of service in MISO		
	MWh	$/MWh	$	MWh	$/MWh	$
Fuel cost	100	$25/MWh	($2,500)	100	$25/MWh	($2,500)
Generator revenue @ $30/MWh Gen Bus LMP				100	$30/MWh	$3,000
Purchased power @ $40/MWh Load Zone LMP				100	$40/MWh	($4,000)
FTR revenue				100	$10/MWh	$1,000
Total			($2,500)			($2,500)

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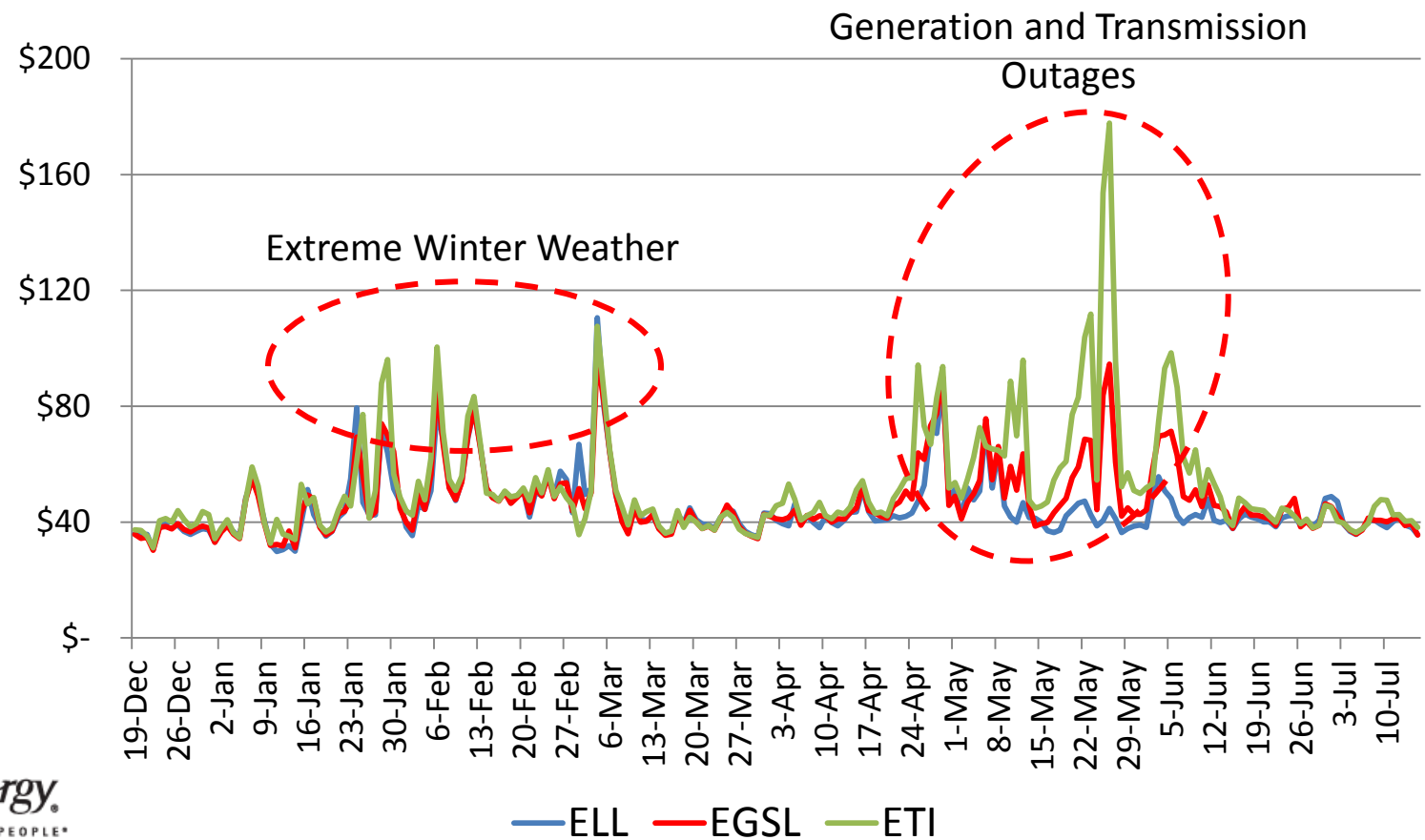
DA Load Zone LMPs

- We have experienced some episodes of relatively high pricing since MISO integration
- For the most part, these episodes are associated with stressed operating conditions
  - Extreme winter weather in MISO South
  - Significant generation and transmission outages in WOTAB



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IMM Quarterly Report: LMPs in Texas and MISO South

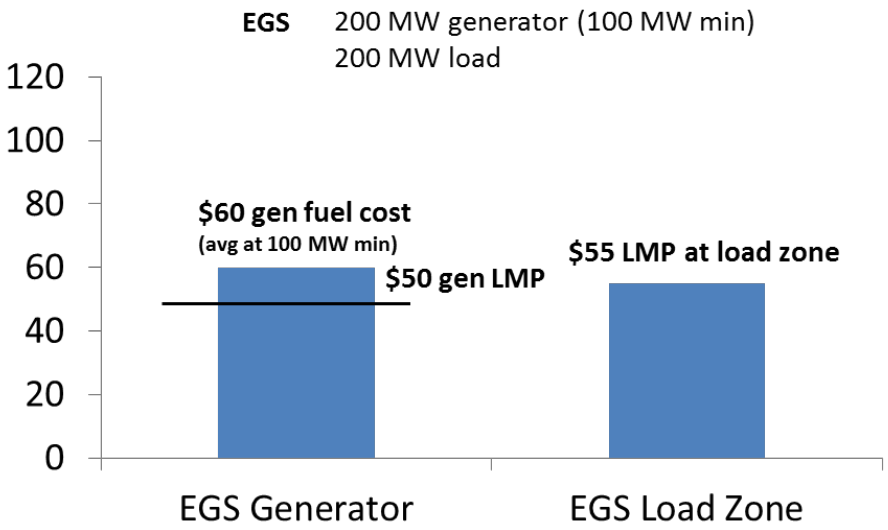
- On June 18, 2014, the MISO IMM (Potomac Economics) provided its quarterly report for March 2014 – May 2014.

- The IMM discussed the high LMPs in the western part of the Entergy service territory.
  - "The most significant congestion this quarter was into Michigan in March and into Texas in the second half of the quarter."
    - "In May, [Day Ahead] prices averaged nearly $80 per MWh at Texas Hub compared to less than $45 at all other hub locations."
  - "In April and May, significant generator and transmission outages in the South resulted in sustained high prices at Texas Hub and the declaration of a number of Local Transmission Emergencies that required the commitment of emergency-only resources."

CUSTOMER COSTS: FUEL + NET MISO BILL

- Illustration of OpCo generators and FTRs acting as hedge against LMPs.
  - LMPs double (increase by 100%) and net customer costs increase by 10%

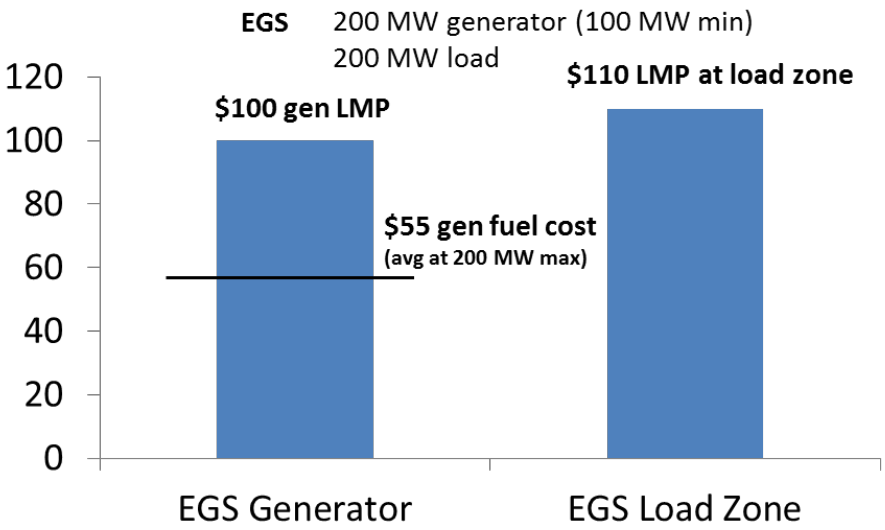
Moderate LMPs



Fuel Cost	(6,000)
Gen LMP	5,000
MWP	1,000
Gen Margin	--
Load LMP	(11,000)
ARR	1,000

FUEL + NET MISO BILL = (10,000)

High LMPs



Fuel Cost	(11,000)
Gen LMP	20,000
MWP	--
Gen Margin	9,000
Load LMP	(22,000)
ARR	2,000

FUEL + NET MISO BILL = (11,000)

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ARRs and FTRs – Definitions

Auction Revenue Rights (ARRs)

- ARRs are financial instruments that entitle their holders to a share of the revenue generated in the annual FTR auction

Financial Transmission Rights (FTRs)

- Right to congestion credits or charges along a path during a given time frame for a certain MW quantity

Auction Revenue Rights (ARRs)

Why	• ARRs are financial instruments that entitle their holders to a share of the Auction revenue, which may then be used to offset cost of transmission congestion
What	• ARRs entitle their holder to a share of the auction revenue (credit or charge) generated in the annual FTR Auction
Who	• ARRs are allocated to Market Participants based on firm historical usage of the transmission network and Market Participants that have funded network upgrades
How	• ARRs are acquired in the annual ARR allocation

Financial Transmission Rights (FTRs)

Why

- As transmission congestion occurs, LMPs vary and provide price signals for efficient market operations, creating uncertainty for MPs, especially in congested areas

What

- FTRs enable their holder to hedge against the cost of congestion in the Day-ahead market

Who

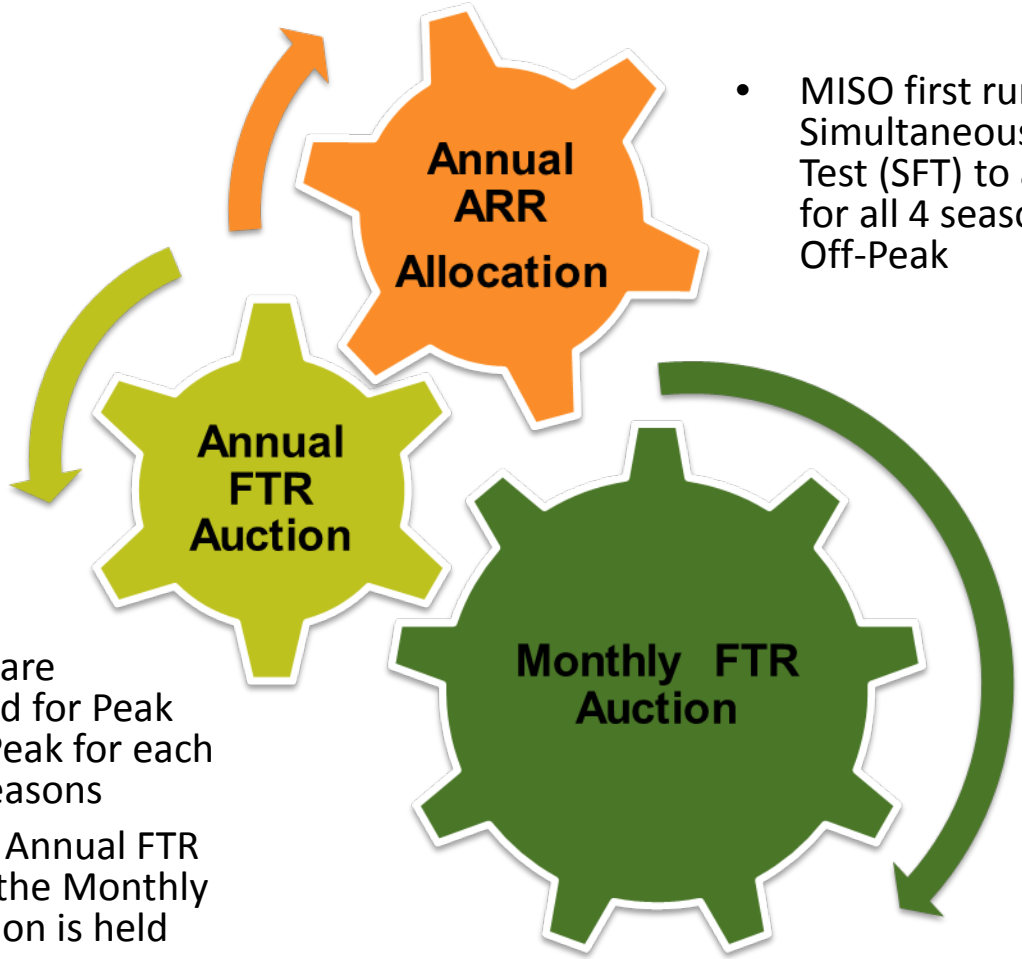
- ARR holders converting ARRs into FTRs
- Any Market Participant with creditworthiness can purchase FTRs

How

- FTRs can be acquired in the Annual or Monthly Auctions
- Acquired as part of a new member integration for entities joining during the planning year
- Secondary market

FTRs / ARRs are Awarded Through a Series of Processes

- The Monthly FTR Auction follows the Annual FTR Auction which follows the Annual ARR Allocation.



- MISO first runs a Simultaneous Feasibility Test (SFT) to award ARRs for all 4 seasons, Peak and Off-Peak

- Auctions are conducted for Peak and Off-Peak for each of four seasons
- After the Annual FTR Auction, the Monthly FTR Auction is held

ARR Concepts

ARRs are financial instruments, not physical rights

- Do not give owners the right to schedule physical use of the transmission system
- Independent of fees associated with transmission service reservations

Hedging mechanism to manage the uncertainty of the cost of acquiring FTRs

- Entitles holder to revenue or charges based on the price of the FTR in the FTR auction
- Do not protect MPs from congestion charges in the Day-Ahead or Real-Time markets

FTRs Allow MPs To Hedge Transmission Congestion Costs

- Provides a right to congestion credits (or charges)

Credit

MCC at the Sink is greater than at the Source point

Charge

MCC at the Source point is greater than MCC at the Sink

Source CPNode (MCC)

FTR:

- MW Quantity
- Source CPNode
- Sink CPNode
- FTR term
- FTR period

Sink CPNode (MCC)

FTR Valuation – Hedge

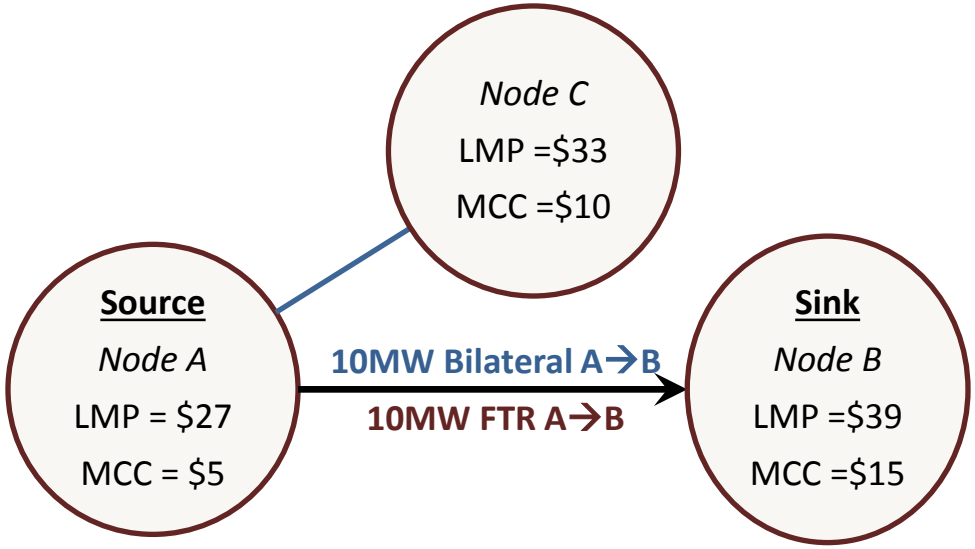
MP holds a 10 MW FTR from A to B which is commensurate with its bilateral transaction

MP is subject to $100 of Day Ahead congestion cost based on market activity but is also entitled to $100 credit for the FTR

MP is hedged against Day- Ahead congestion cost

Description	Sink	Source	MW	Total
DA Congestion Cost	($15	- $5) *	10	= 100
Description	**Source**	**Sink**	**MW**	**Total**
FTR Target Credit	($5	- $15) *	10	= -100
			Net:	**$0**

Note: FTR Target Credit calculation is reversed to indicate cash flows with respect to MISO
(-) MISO pays, (+) MISO collects



ARR Allocation – Conducted in Stages

Stage 1A Nominations	Restoration	Stage 1B Nominations	Stage 2
Up to 50% of Peak Usage	Processing of curtailed Stage 1A Candidate ARRs	Up to 100% of Peak Usage	No Nomination
Candidate Baseload ARR Rights	Processing of LTTR Termination Requests	Candidate Peak ARR Rights	Difference between Stage 1 Nominations Cap and ARRs

- ARR Obligations are awarded in stages during the Annual ARR Allocation subject to simultaneous feasibility

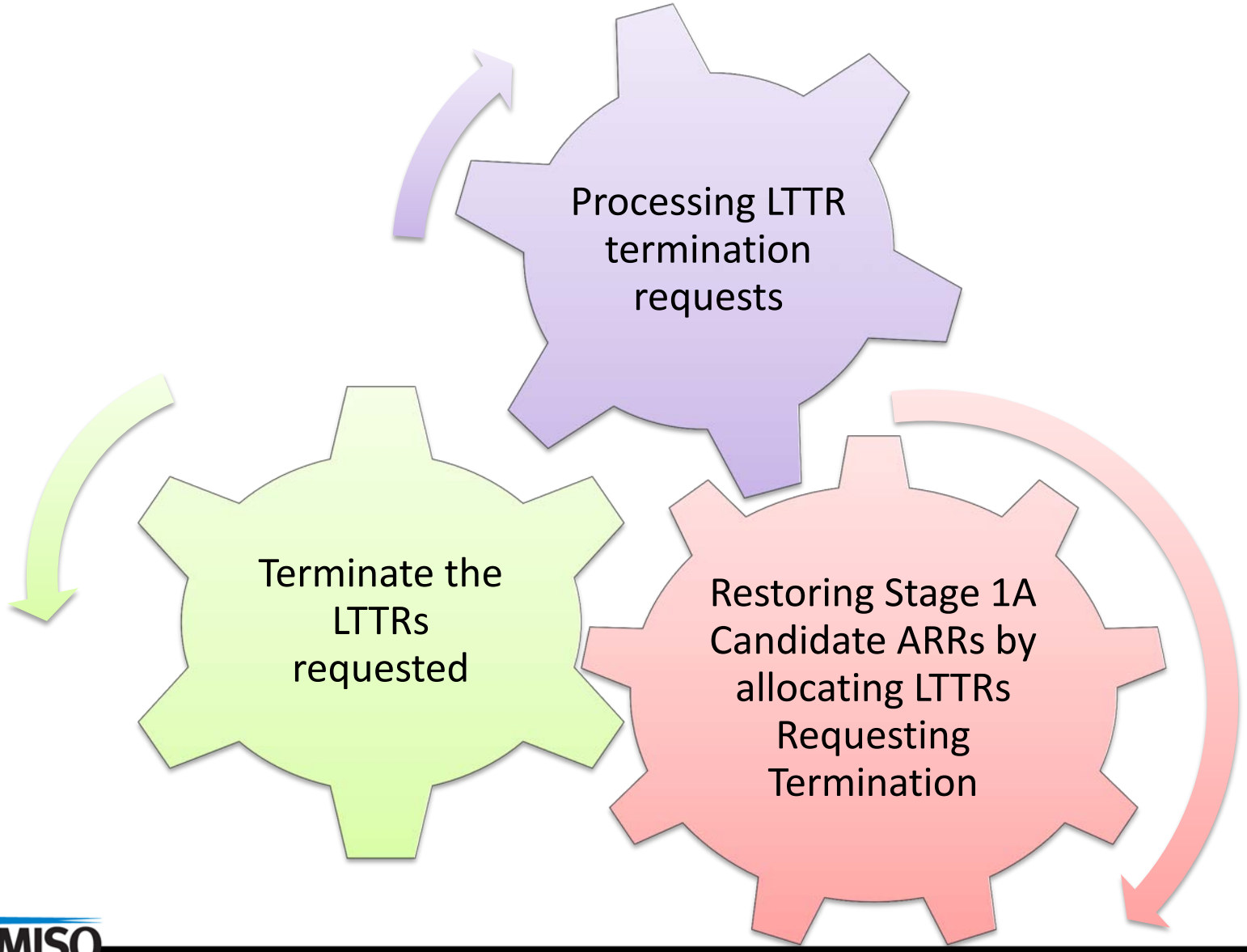
ARR Allocation – Stage 1A

- ARRs allocated in Stage 1A are called Long-Term Transmission Rights (LTTRs)

Nomination of ARR entitlements which have a source at a base loading resources (BRSS)

Allocated Stage 1A ARRs are guaranteed for the next year's allocation, as long as they are nominated

ARR Allocation Restoration Step – LTTR Termination with Restoration



ARR Allocation 1B and 2

- FTR Auction excess revenue is the dollar amount held by MISO after receiving and making payments associated to Bids and Offers cleared in the auction and Allocated ARRs

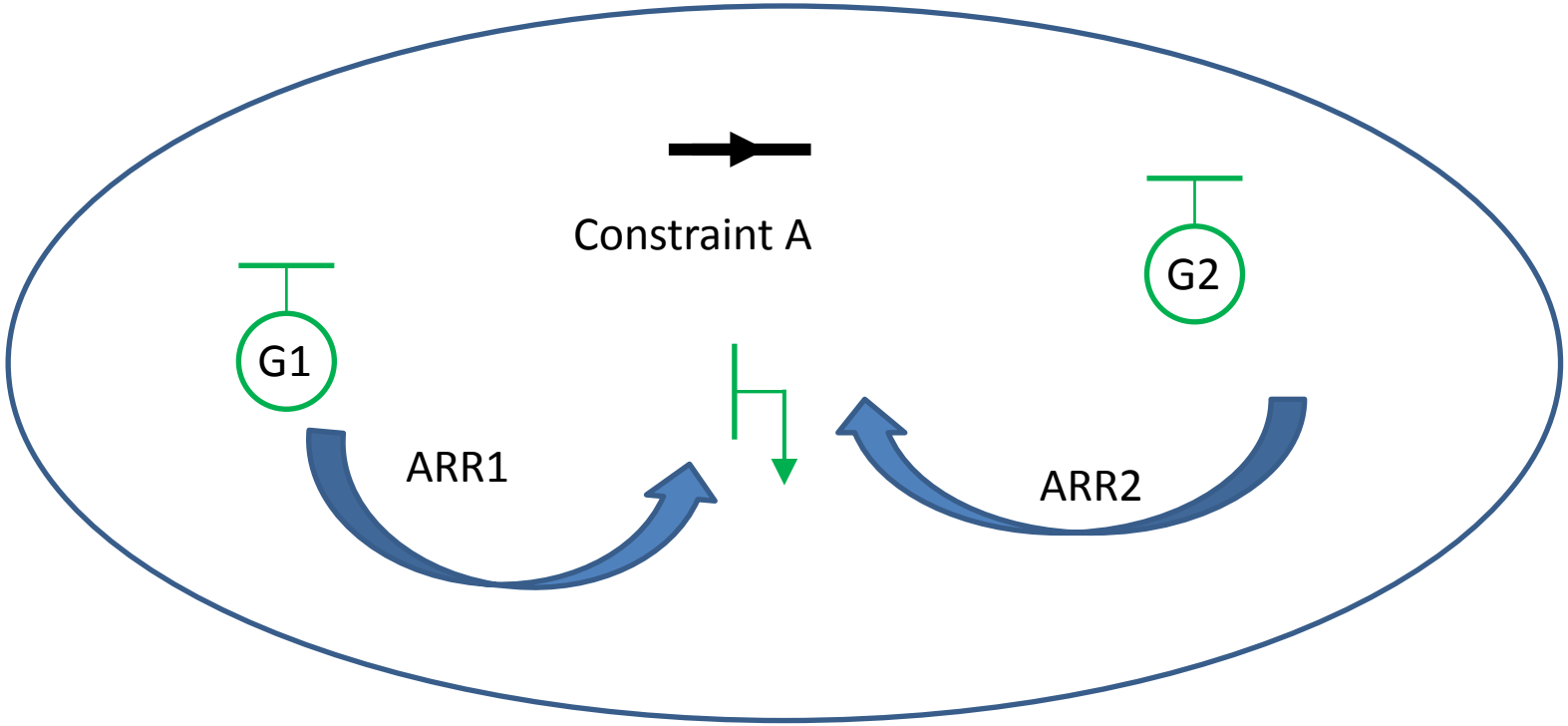
Stage 1B

- Allows MPs to nominate up to 100% of their entitlements that are not already allocated in Stage 1A and Restoration

Stage 2

- Assignment of rights to a share of the excess FTR auction revenue based on each MPs unallocated eligible MW
- MPs that did not receive ARRs for their full allocation eligibility, will receive a share of the excess auction review

Graphical Examples



ARR2 is a counterflow ARR per its impact on Constraint A

Background

- In Year 1 of MISO's Annual Allocation, counterflow ARRs will be assigned to the Market Participants (MP) with historical Baseload and high utilization factor resources in the reference year

- MISO objective as part of the allocation is to maximize the allocation of rights in stage 1A and restoration based on available counterflows
  - In conjunction, attempts to maximize subject the simultaneous feasibility, the termination of LTTRs for which LTTR termination requests were made

LTTR termination Process

- Starting in Year 2, Market Participants can request the termination of assigned counterflow ARRs.
- As part of the restoration stage, MISO performs a Simultaneous Feasibility Test (SFT) to determine whether the termination can be granted
  - SFT determines whether the counterflow ARRs are needed to render feasible otherwise unfeasible LTTRs
  - The counterflow ARR requested for termination may be kept active up to 10 years

Year 1 Counterflow Termination for an expiring PPA

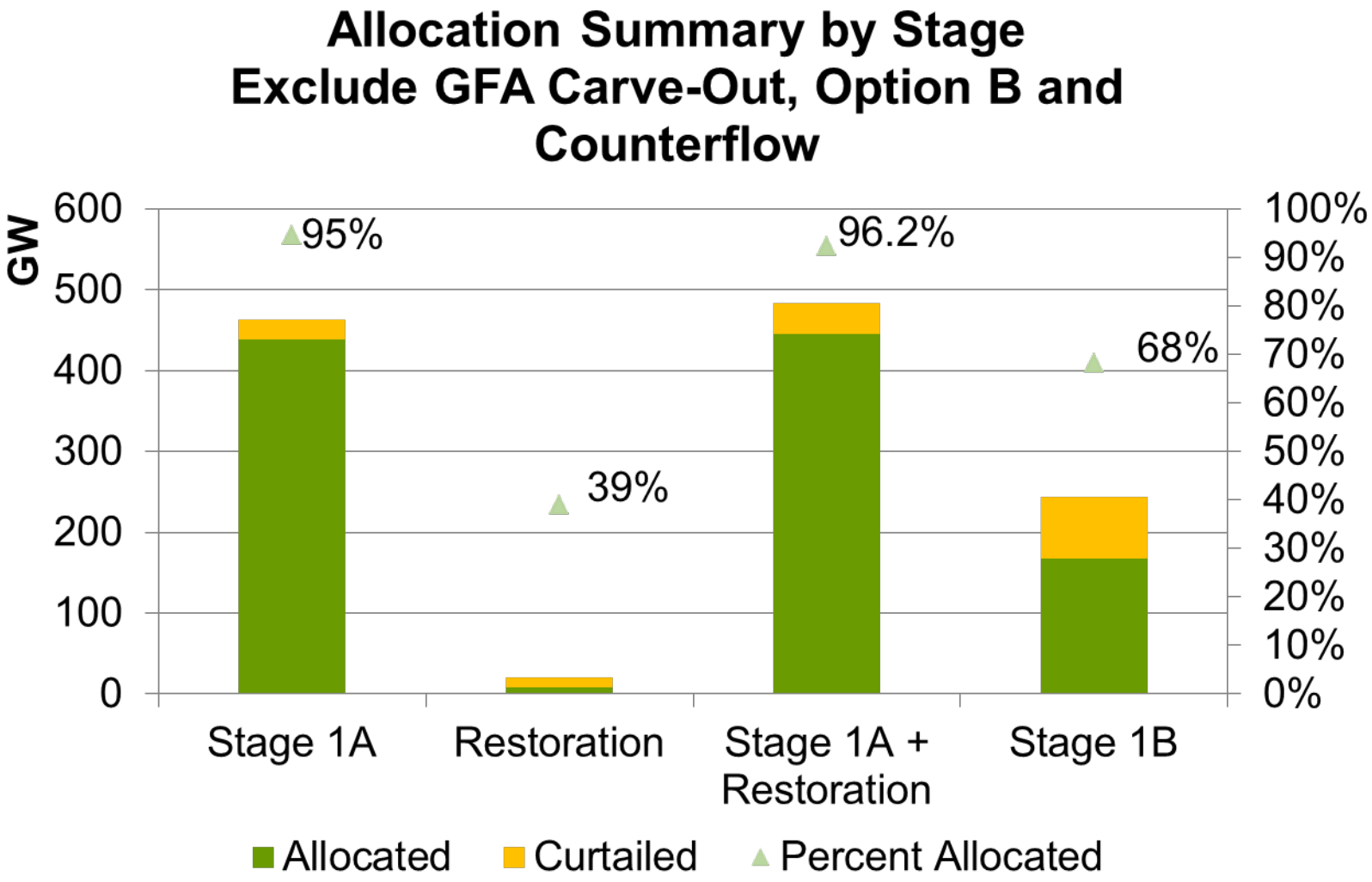
- A Market Participant may request the termination of an RSP that has associated year 1 Counterflow ARRs when
  - Generation resource is retiring, or
  - PPA is expiring
- Market Participants must provide a notice to MISO before the expected retirement or PPA expiration.
  - In this scenario, the counterflow ARR can be terminated after 5 years instead of the 10 year requirement
  - Waiver: if Generation Resource was rendered inoperable immediately and permanently due to a catastrophic failure of the Generation Resource, the termination will be effective in the next full Season

2014-15 Allocation Summary Overview (Stage 1)

2014-15	Season	Summer		Fall		Winter		Spring		Total
	TOU	Off peak	Peak	Off peak	Peak	Off peak	Peak	Off peak	Peak	
Stage 1A*	Nominated	57582.6	61169.1	55985.3	59042.5	56122.2	60477	54119.1	58512.6	463010.4
	Allocated	54154.5	57138.2	53533.4	56184.7	54019.5	57911.3	51224.3	53614.8	437780.7
	Percent	94%	93%	96%	95%	96%	96%	95%	92%	95%
Restoration**	Nominated	2641.2	3437.2	1974.8	2290.3	1739.2	2185.4	2327.3	4057.7	20653.1
	Allocated	1245.8	1335.3	781.8	781.7	763.3	1134.3	752.1	1255.3	8049.6
	Percent	47%	39%	40%	34%	44%	52%	32%	31%	39%
Stage 1B*	Nominated	31330.8	37301.9	27673.4	31001	27374.2	31143.5	27661.7	30809.8	244296.3
	Allocated	21661.7	27235	16944.8	20676.9	18654.8	21755.5	17625.7	22283.5	166837.9
	Percent	69%	73%	61%	67%	68%	70%	64%	72%	68%
Total*	Nominated	91554.6	101908.2	85633.5	92333.8	85235.6	93805.9	84108.1	93380.1	727959.8
	Allocated	77062	85708.5	71260	77643.3	73437.6	80801.1	69602.1	77153.6	612668.2
	Percent	84%	84%	83%	84%	86%	86%	83%	83%	84%

*exclude MISO_OB, MISO_CO, MVP
**exclude the Counterflow assignment

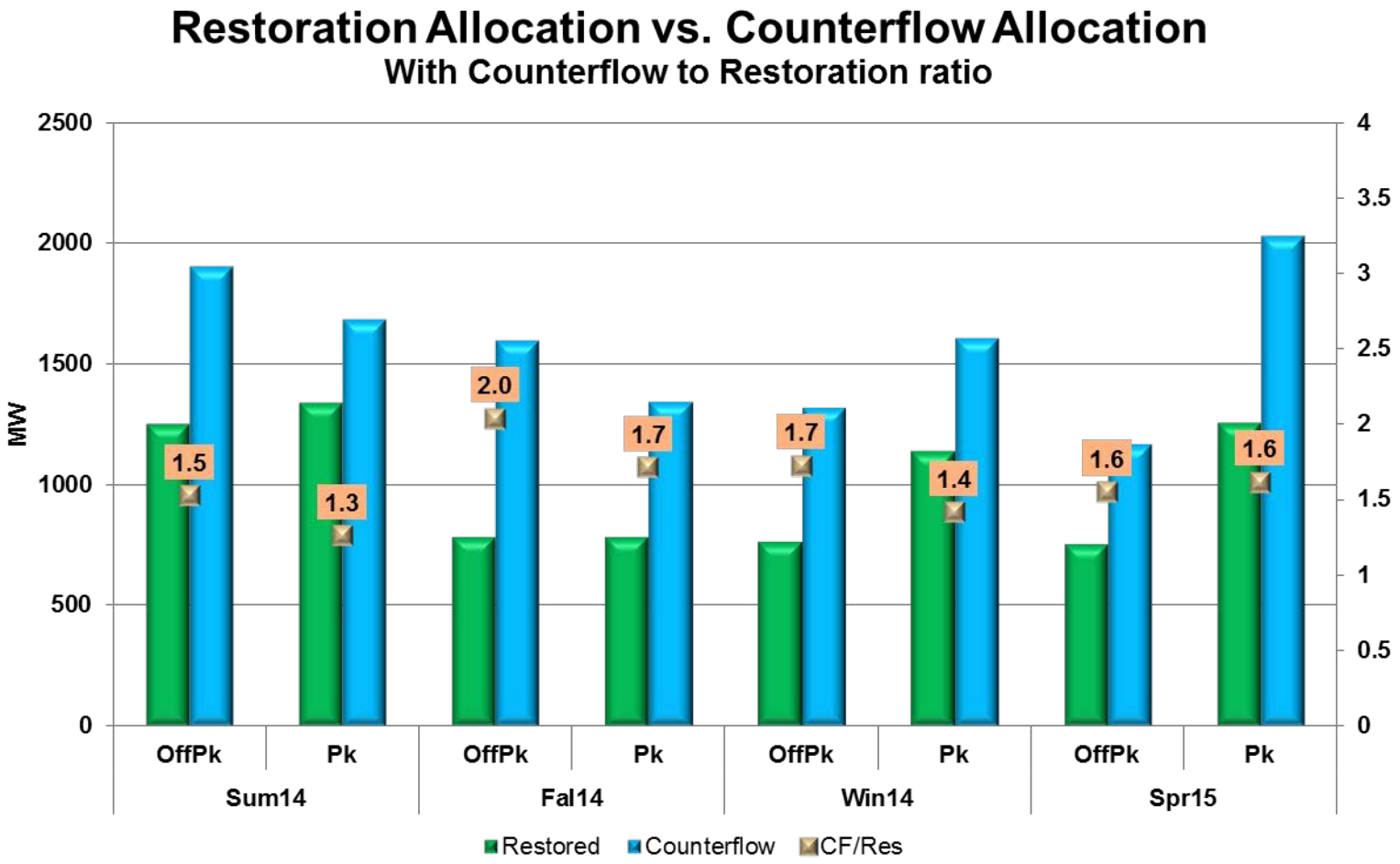
2014-15 Allocated ARRs by Stage



2014-15 Restoration and Counterflow Summary

2014-15	Season	Summer		Fall		Winter		Spring		Total
	TOU	Off peak	Peak	Off peak	Peak	Off peak	Peak	Off peak	Peak	
Restoration	Nominated	2641.2	3437.2	1974.8	2290.3	1739.2	2185.4	2327.3	4057.7	20653.1
	Allocated	1245.8	1335.3	781.8	781.7	763.3	1134.3	752.1	1255.3	8049.6
	Percent	47%	39%	40%	34%	44%	52%	32%	31%	39%
Counterflow	Eligible	7631.5	8646.3	10036.7	8920.3	9795.6	8383.7	10656.2	9397.2	73467.5
	Allocated	1899.6	1683.1	1593.6	1338.7	1316.2	1605.2	1165.9	2027.6	12629.9
	Percent	25%	19%	16%	15%	13%	19%	11%	22%	17%

2014-15 Restoration vs. Counterflow



Overall counterflow to restoration ratio of 1.56 in 2014 allocation (vs. 1.3 in 2013 allocation)

Counterflow Assignments to ELL and EGSL

- ELL and EGSL both received an assignment of counterflow ARRs in the annual ARR allocation process – approximately 700 MW on average across the eight delivery periods
  - The assignment of counterflow ARRs was not unanticipated, and the amount assigned is roughly consistent with the Companies' expectations

- It remains true that an OpCo's cost to serve load from its generator will be identical to its pre-MISO cost if the OpCo has an FTR from the generator, even if the FTR is negative.

Assumptions:	Cost of service Pre-MISO			Cost of service in MISO		
	MWh	$/MWh	$	MWh	$/MWh	$
Fuel cost	100	$25/MWh	($2,500)	100	$25/MWh	($2,500)
Generator revenue @ $40/MWh Gen Bus LMP				100	$40/MWh	$4,000
Purchased power @ $30/MWh Load Zone LMP				100	$30/MWh	($3,000)
FTR revenue				100	($10/MWh)	($1,000)
Total			($2,500)			($2,500)

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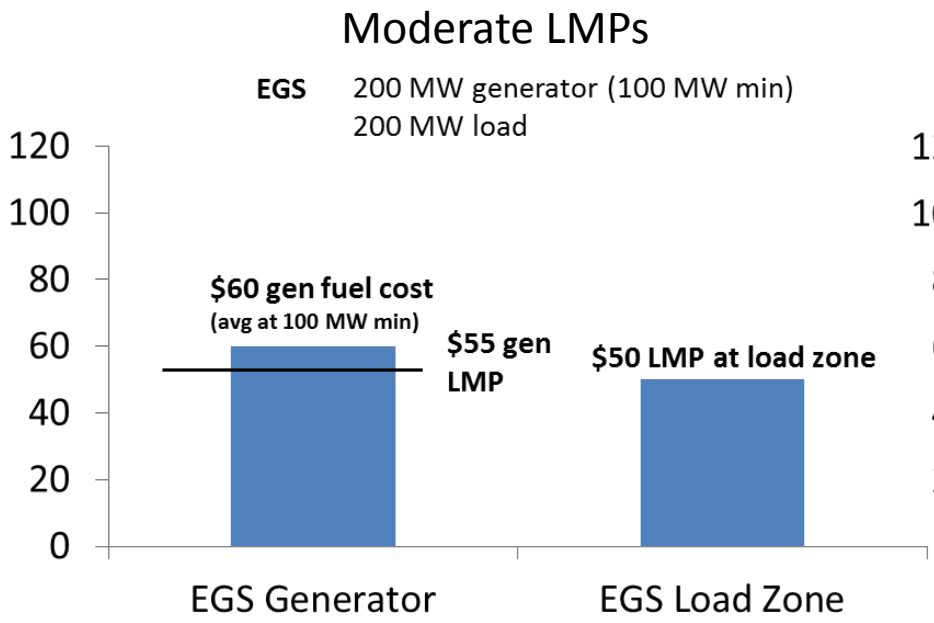
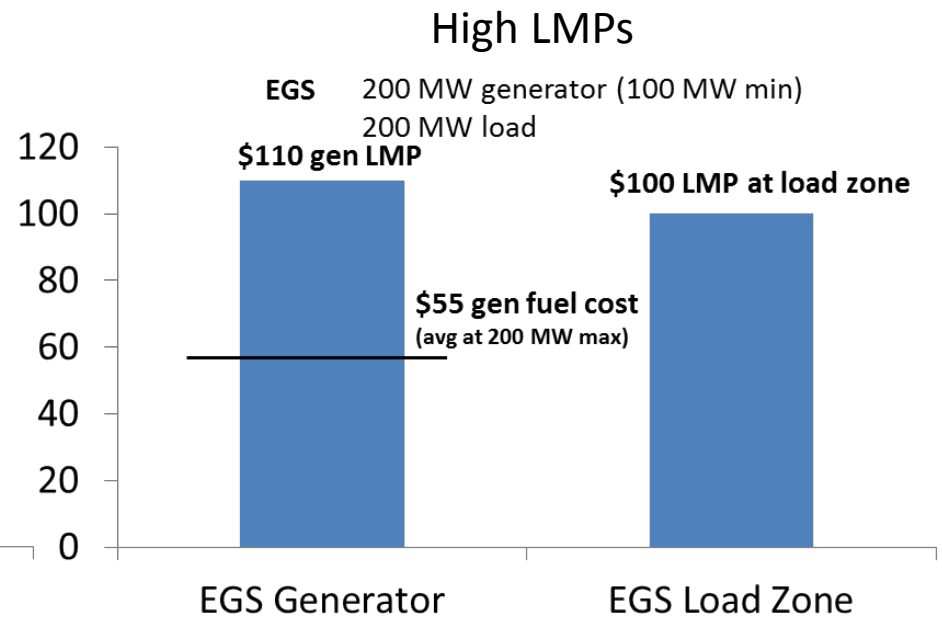
Overall ARR/FTR Assignments to ELL and EGSL

- ELL and EGSL are comfortable with their portfolios of ARRs, including counterflow ARRs
  - The portfolios of FTRs held by ELL and EGSL during the stub period (12/19/13-5/31/14) provided an effective hedge against congestion charges.
  - The annual portfolios of ARRs now held by ELL and EGSL are superior in some respects to the stub period portfolios (higher allocation of non-counterflow ARRs, stage 2 revenues), and would have been valued more highly during the stub period than the stub period portfolios that provided an effective hedge.
- ELL and EGSL plan to seek relief from counterflow obligations
  - ELL and EGSL plan to request termination of counterflow ARRs in the upcoming annual ARR allocation process; such termination requests will be granted by MISO subject to simultaneous feasibility that may be made possible by, for instance, transmission upgrades.
  - ELL and EGSL plan to give notice to MISO if a unit that is the source of a counterflow ARR retires or is the source of a contract that expires; MISO will terminate the counterflow ARR entitlements and associated counterflow ARRs five years after notice of such retirement or contract expiration is provided

CUSTOMER COSTS: FUEL + NET MISO BILL WITH COUNTERFLOW ARR





Fuel Cost	(6,000)
Gen LMP	5,500
MWP	500
Gen Margin	--
Load LMP	(10,000)
ARR	(1,000)
FUEL + NET MISO BILL =	**(11,000)**

Fuel Cost	(11,000)
Gen LMP	22,000
MWP	--
Gen Margin	11,000
Load LMP	(20,000)
ARR	(2,000)
FUEL + NET MISO BILL =	**(11,000)**

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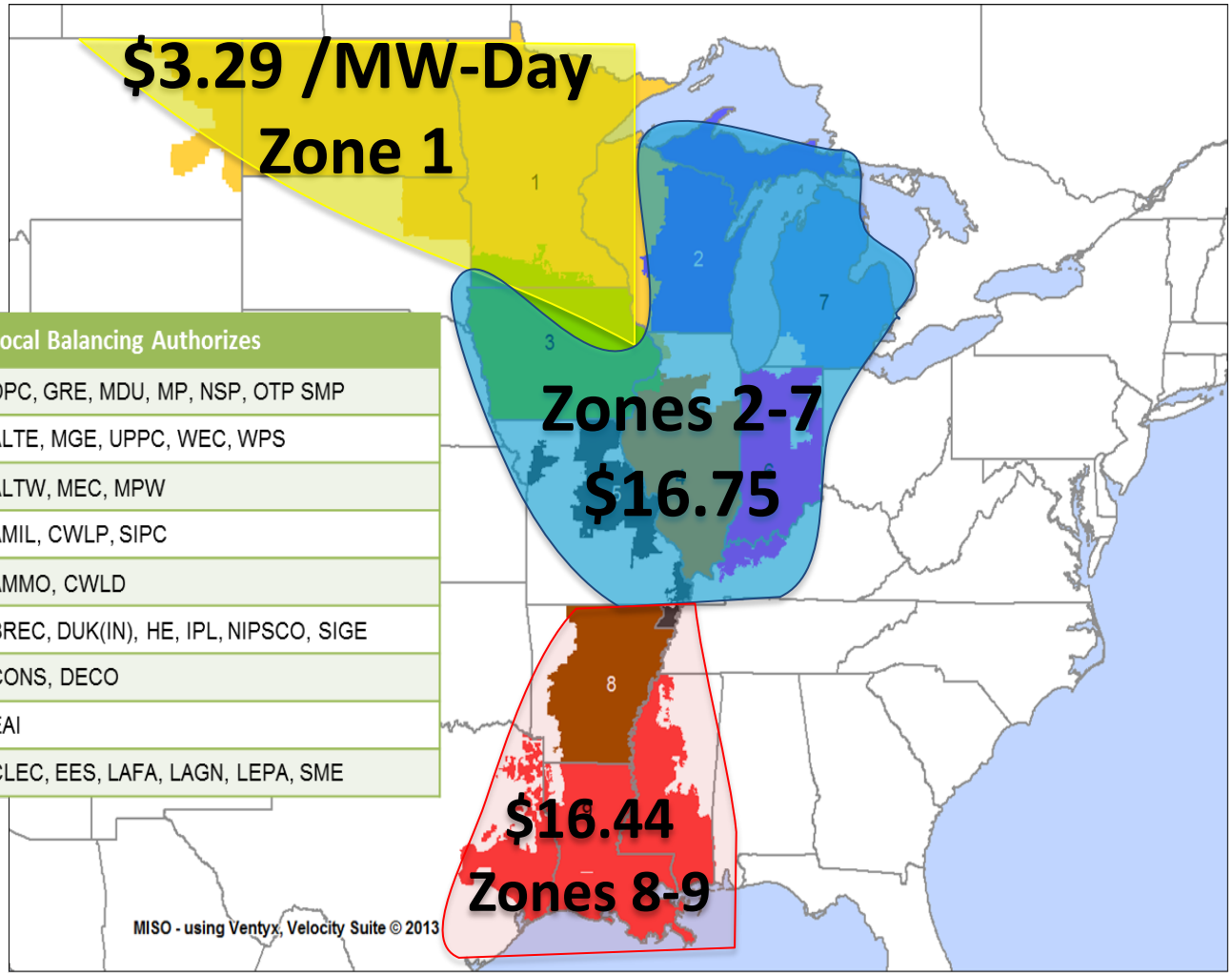
Technical Conference Agenda

- Locational Marginal Price (LMP)
- Auction Revenue Rights (ARR) and Financial Transmission Rights (FTR)
- **Resource Adequacy**
- Transmission Planning
- Communications for Emergency Conditions
- Value Proposition

Executive Summary

- MISO projects adequate reserves to meet 2014 Summer Peak demand
- The reduced post-2014 projected reserve margins reflect tighter supply due to retirements and will result in a higher probability of calling emergency only resources
- MISO continues to coordinate with neighbors as we seek to eliminate barriers and inefficiencies across adjoining seams to maximize value for consumers
  - During the polar vortex, MISO successfully managed system assets within the its region while also supporting and assisting neighboring entities in their efforts to do the same
- The outlook for 2015/2016 illustrates a significant reduction in resources across the footprint
- MISO is exploring the feasibility of establishing a seasonal resource adequacy model to reflect changing conditions

2014/15 Planning Resource Auction



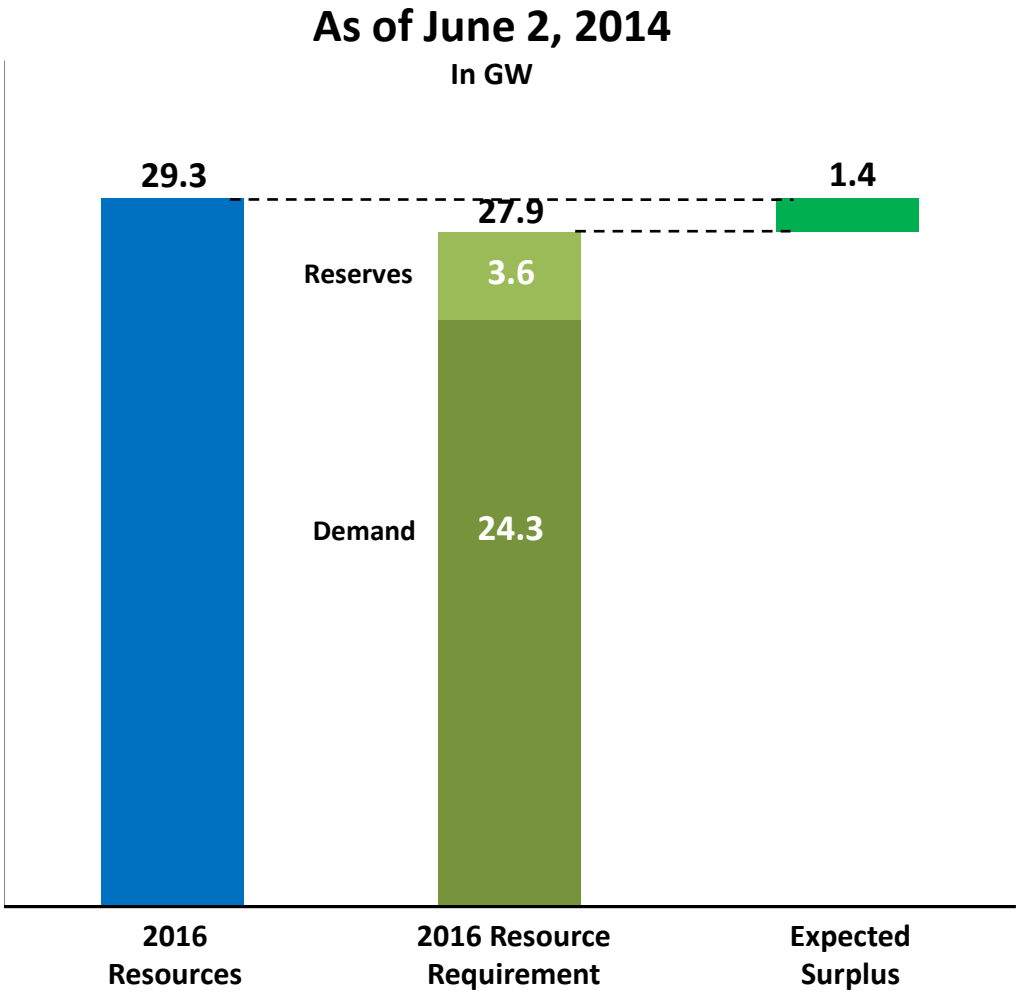
LRZ	Local Balancing Authorizes
1	DPC, GRE, MDU, MP, NSP, OTP SMP
2	ALTE, MGE, UPPC, WEC, WPS
3	ALTW, MEC, MPW
4	AMIL, CWLP, SIPC
5	AMMO, CWLD
6	BREC, DUK(IN), HE, IPL, NIPSCO, SIGE
7	CONS, DECO
8	EAI
9	CLEC, EES, LAFA, LAGN, LEPA, SME

LRZ 9 Reserve Requirement: 25.2 GWs

0.8 GWs above requirement cleared to support North/Central Resource Adequacy needs

Surplus un-cleared capacity in auction: ~2.2 GWs

2016 Projected Resource Adequacy



All capacity in Installed Capacity values (ICAP)

MISO Resource Adequacy Construct – System wide and Local reserve requirement

- MISO Planning Reserve Requirement (PRM):
  - Based on 1 day in 10 LOLE criteria applied MISO system
  - Applied to Load Serving Entity demand coincident with MISO peak

- Local Clearing Requirement (LCR):
  - Establishes minimum reserves needed to be physically located within each zone to meet zonal 1 day in 10 LOLE criteria
  - Calculated as: LRR – CIL
    - LRR: Local Reliability Requirement – 1 day in 10 LOLE criteria applied to each zone in isolation of other zones. Applied to Zonal Peak demand.
    - CIL: Capacity Import Limit – Maximum transmission import capability

Transmission Limits between zones at the heart of MISO Resource Adequacy Construct

- Capacity Import and Export limits are established for each Local Resource Zone
  - Import limits establish maximum transmission capacity to allow transfer of Planning Resources into each zone
  - Export limits establish maximum transmission capacity to allow transfer of Planning Resources from each zone to rest of MISO system

- Simultaneous Feasibility Test
  - Conducted within the auction period using Planning Resource dispatch consistent with cleared capacity
  - Determines simultaneous feasibility of transactions between zones.
  - Some transactions are modified to maintain reliability.

Zonal Resource Credits (ZRCs)

- Zone specific amount of UCAP volume (MW) that has been converted from a qualified resource to participate in the PRA

- PRA is cleared on an Unforced Capacity (UCAP) basis
  - Supports bilateral trades by recognizing the UCAP value of each resource
  - Fair recognition of contribution each unit provides towards Resource Adequacy
  - Market signals that will promote generating unit availability performance

- Available ZRCs can be transferred between market participants

- Zone 9 eligible resource in 2014/15 PRA
  - 29,520 MWs Generation
  - 176 MWs Behind the Meter Generation (BTMG)
  - 219 MWs Demand Resources (DR)
  - 590 MWs External Resources

Fixed Resource Adequacy Plan (FRAP)

- Allows MP to opt-out of yearly auction to avoid any potential price impacts resulting from the PRA
- Load Serving Entities can use FRAP to meet 100% of their PRM and LCR
  - Using resources that LSE has ownership or contractual rights
  - Each resource must meet the qualification requirements
- Any portion of an LSE's PRMR not covered by the FRAP can be purchased through the Planning Resource Auction

The generation fleet in MISO is being affected by timing, fuel prices and multiple environmental regulations

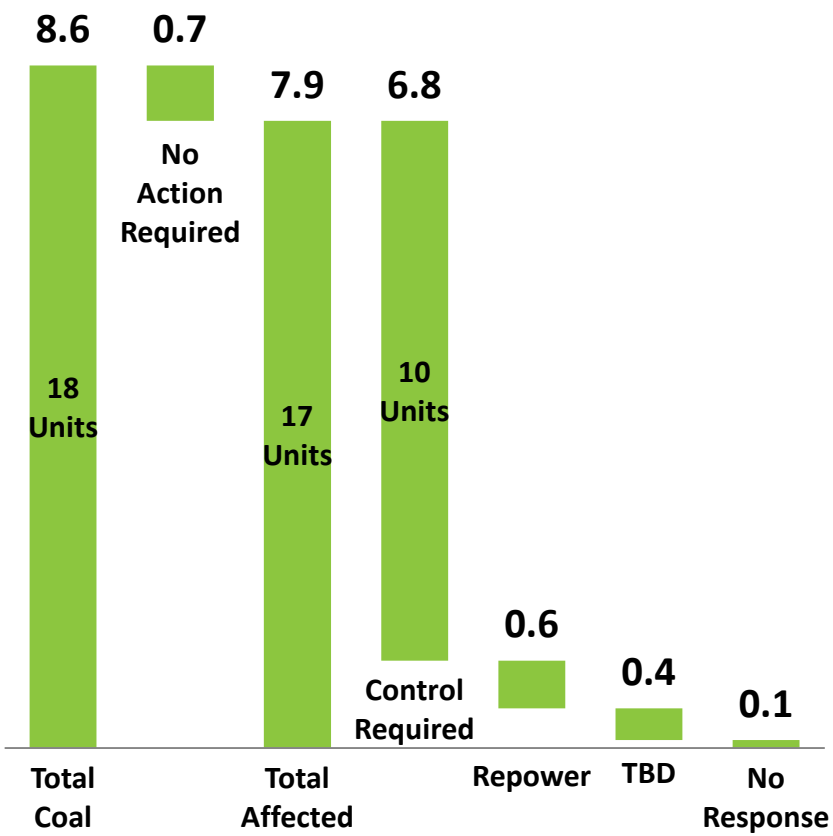
	MATS	CSAPR & CWA	GHG	NAQQS & Coal Ash?
Nature of Regulation	Mercury and Air Toxics Standards	Cross State Air Pollution Rule and Water Regulations (316(b))	Carbon Regulations (Clean Power Plan)	National Ambient Air Quality Standards? Coal Ash?, Others?
Compliance Dates	2015 / 2016	As early as 2015	2020-2029, 2030 and beyond	???
Impacts	• Significant coal retirements • Outage coordination challenges • Shrinking reserve margins around MISO • Growing dependence on natural gas	• CSAPR is subject to ongoing litigation • EPA sought lift of stay on CSAPR – could make rule effective as early as 2015 • Final water intake rule released May 2014	• Draft Rule released June 2014 • Continued pressures on reserve margins • Increased dependence on natural gas • Regulatory uncertainty	

These factors will culminate in the erosion of reserve margins and an increase in reliability risk.

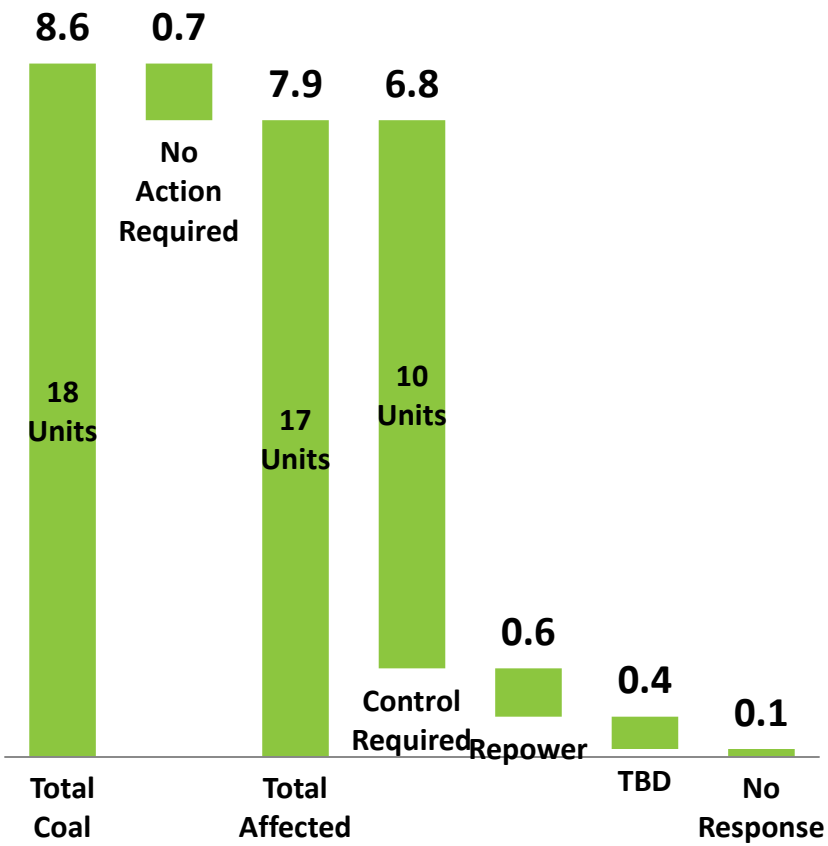
MISO

MISO South 4th Q 2013 Survey to 1st Q 2014 Survey

Coal Resources Affected 4th Q 2013 Survey Capacity, GW

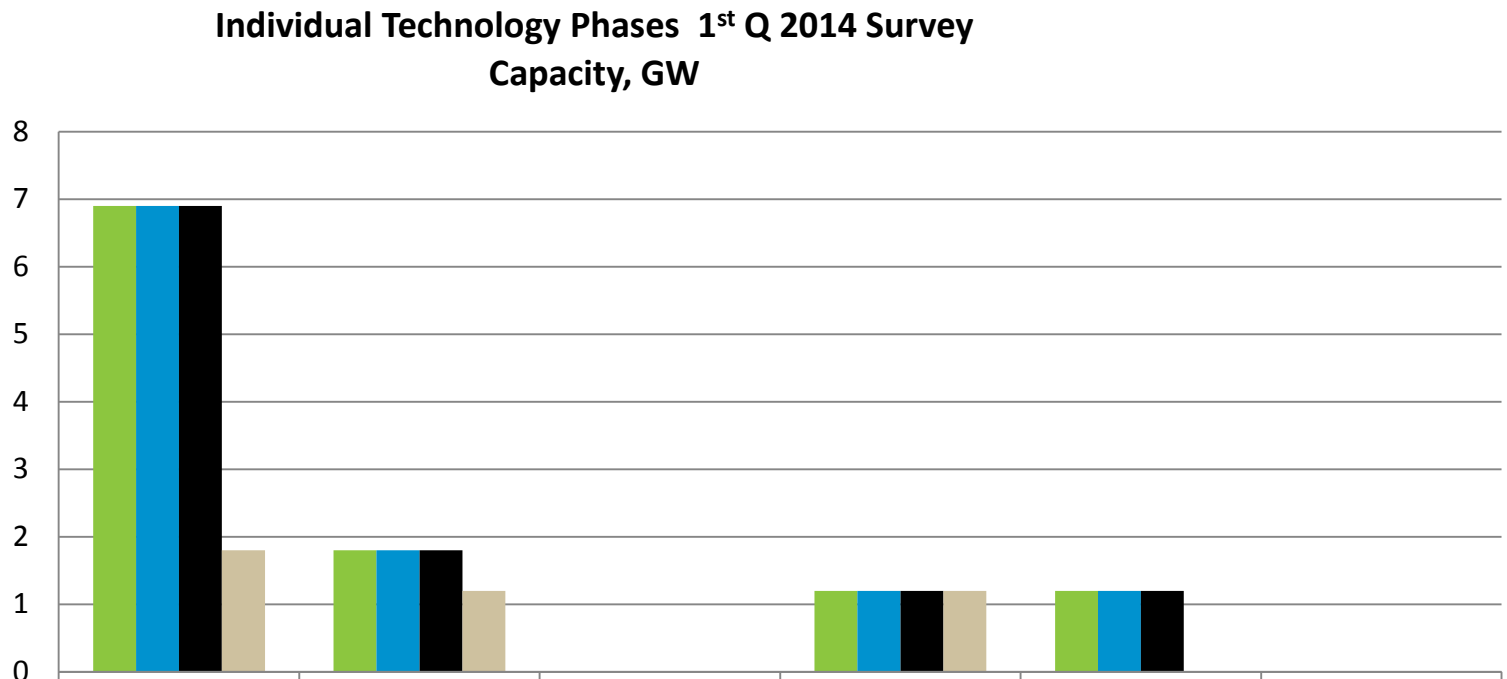


Coal Resources Affected 1st Q 2014 Survey Capacity, GW



4.3 GW comprising of 7 units have approved 1-year extensions

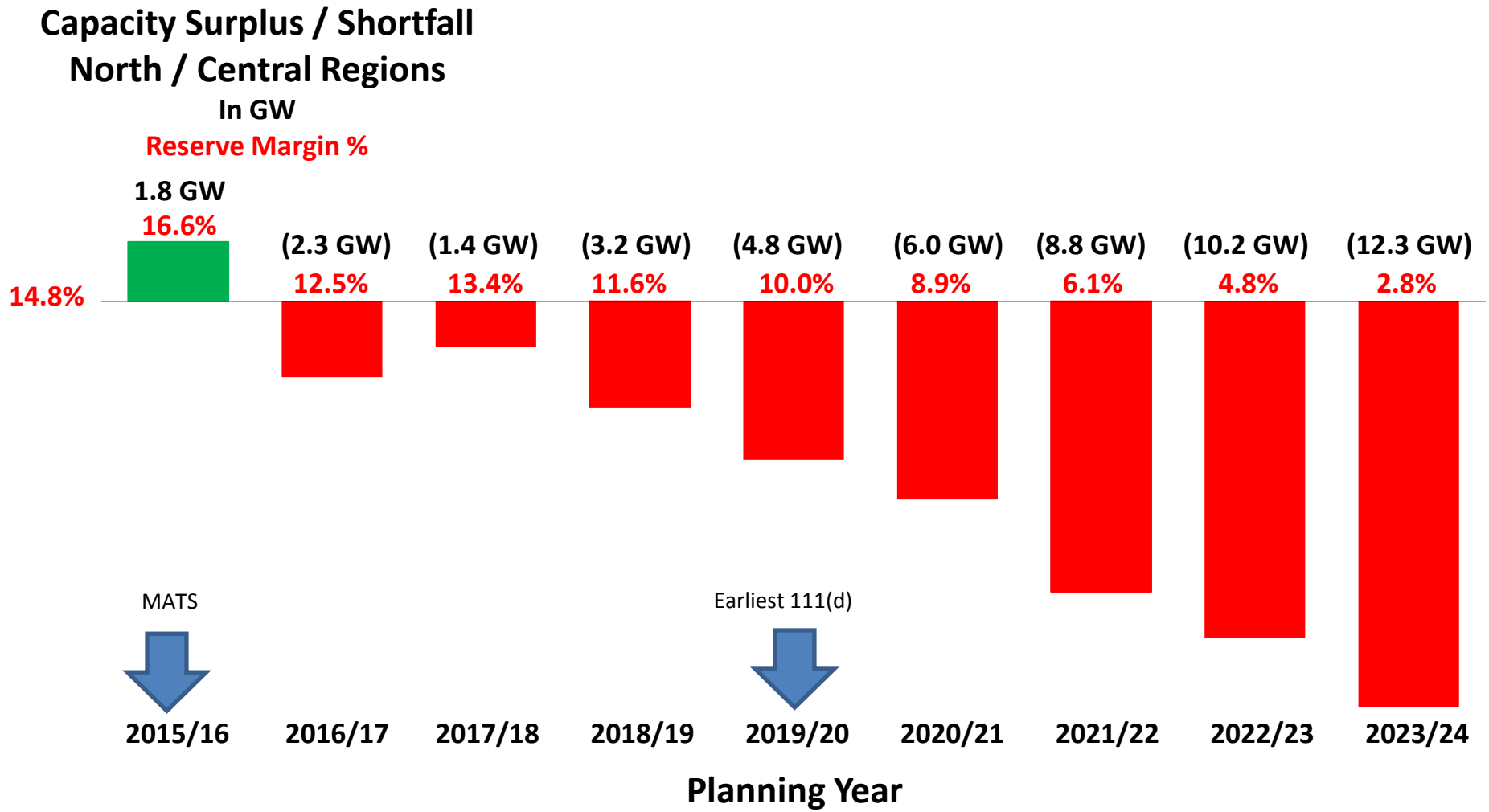
MISO South Emission Technology Phases



	ACI	DSI	FGD	Baghouse	SCR	ESP
Work Required (GW)	6.9	1.8	0.0	1.2	1.2	0.0
Work Scheduled (GW)	6.9	1.8	0.0	1.2	1.2	0.0
Work Contracted (GW)	6.9	1.8	0.0	1.2	1.2	0.0
Outage Scheduled (GW)	1.8	1.2	0.0	1.2	0.0	0.0

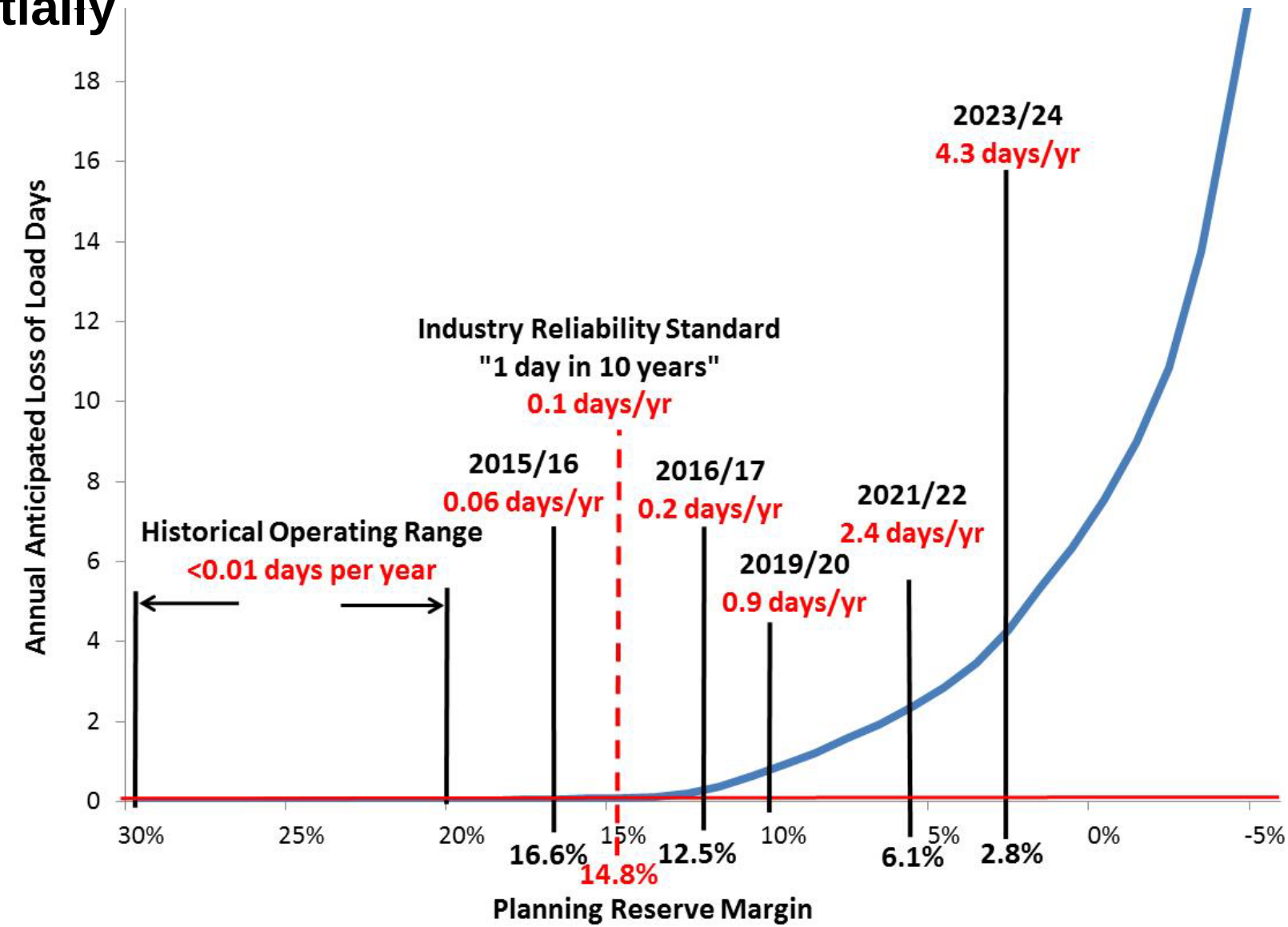
ACI: Activated Carbon Injection; **DSI**: Dry Sorbent Injection;
FGD: Flue Gas Desulfurization; **SCR**: Selective Catalytic Reduction; **ESP**: Electrostatic Precipitator

The region is showing a need for additional resources to meet projected load growth



This slide shows **forecast** of a 10-year period, as is required for the NERC Long Term Reliability Assessment. MISO expects that **these figures will change significantly as future capacity plans are solidified** in the future by load serving entities and state commissions.

As planning reserves erode the probability of loss of load and reliance on Emergency Operating Procedures increase exponentially



MISO

14/15 PRA Results for MISO South: Pricing

- MISO's annual capacity auction (Planning Resource Auction) is a voluntary auction that represents a short-term option that can be used to meet an OpCo's needs.
  - This represents just one of the options available to the OpCo's to meet MISO's resource adequacy requirements.
  - The Companies have and anticipate the they will continue to use other, longer-term options (i.e., owned and contracted units), as the primary mechanism to meet their capacity needs in MISO, and therefore the Companies' exposure to price volatility in the Planning Resource Auction will be substantially mitigated.
- MISO's recent annual capacity auction for the 2014/2015 year cleared at $0.50/kW-month ($16.44/MW-day) for the Companies' LRZ (LRZ 9).
  - While this is an increase above the $0 clearing price from the transitional auction, it still represents a very low capacity price.
  - The MISO Cost of New Entry ("CONE") for the 2014/2015 year was $7.57/kW-month ($249/MW-day).
- The results reflect prices for the 2014/2015 year, not other future years.
  - Supply and demand are dynamic (additions, retirements, load growth), and therefore price outcomes for future auctions are uncertain.

14/15 PRA Results for MISO South: Surplus

- Total surplus in MISO South = 38,141 – 33,641 = 4,500 MW
  - There is currently a capacity surplus in MISO South
- Exports from MISO South = 34,641 – 33,641 = 1,000 MW
  - Exports from MISO South were limited to 1,000 MW in the 14/15 PRA
- Net surplus in MISO South = 4,500 – 1,000 = 3,500 MW

14/15 PRA Results

	LRZ 8 (AR)	LRZ 9 (TX, LA, MS)	Total
Supply	9,803	28,338	38,141
Offer submitted	9,406	25,966	35,372
FRAP submitted	397	2,372	2,769
Demand	8,417	25,224	33,641
Offer cleared + FRAP	8,582	26,059	34,641

4,500 MW surplus

1,000 MW exports

Source: MISO Supply Adequacy Working Group presentation, 5/1/14.

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Technical Conference Agenda

- Locational Marginal Price (LMP)
- Auction Revenue Rights (ARR) and Financial Transmission Rights (FTR)
- Resource Adequacy
- **Transmission Planning**
- Communications for Emergency Conditions
- Value Proposition

MISO Planning Objectives

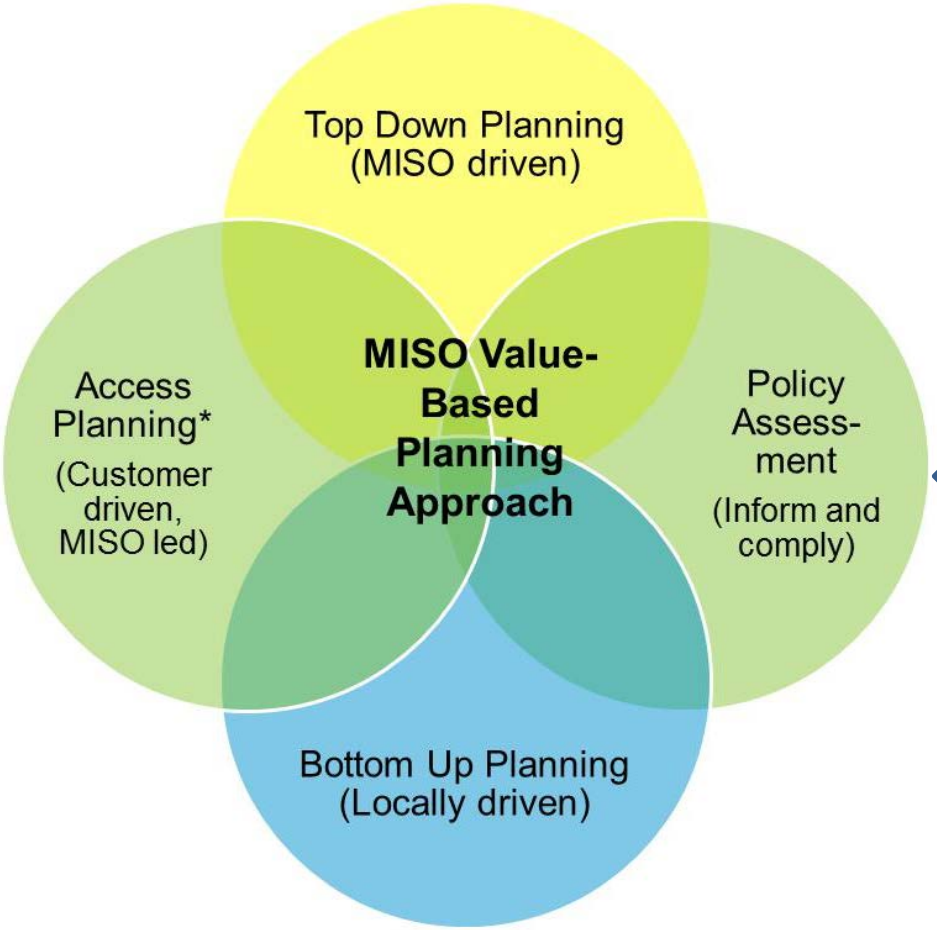
Fundamental Goal

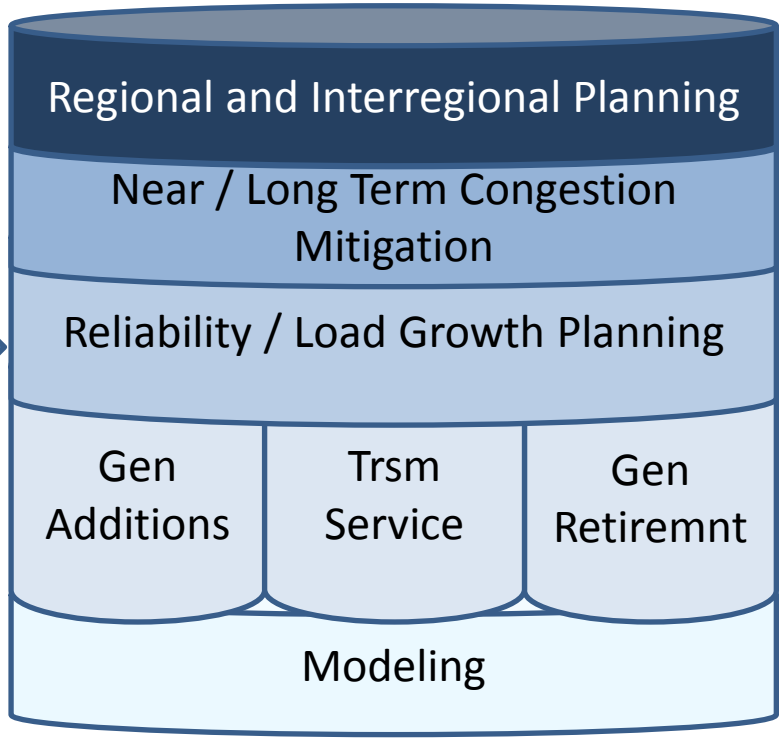
The development of a **comprehensive** expansion plan that meets **reliability needs, policy needs, and economic needs**

MISO Board of Directors Planning Principles

- Make the benefits of an economically efficient electricity market available to customers by identifying transmission projects which **provide access to electricity at the lowest total electric system cost**
- Develop a transmission plan that **meets all applicable NERC and Transmission Owner planning criteria** and safeguards local and regional reliability through identification of transmission projects to meet those needs
- **Support state and federal energy policy requirements** by planning for access to a changing resource mix
- **Provide an appropriate cost allocation mechanism** that ensures that costs of transmission projects are allocated in a manner roughly commensurate with the projected benefits of those projects
- **Analyze system scenarios and make the results available to state and federal energy policy makers** and other stakeholders to provide context and to inform choices
- **Coordinate planning processes with neighbors** and work to eliminate barriers to reliable and efficient operations

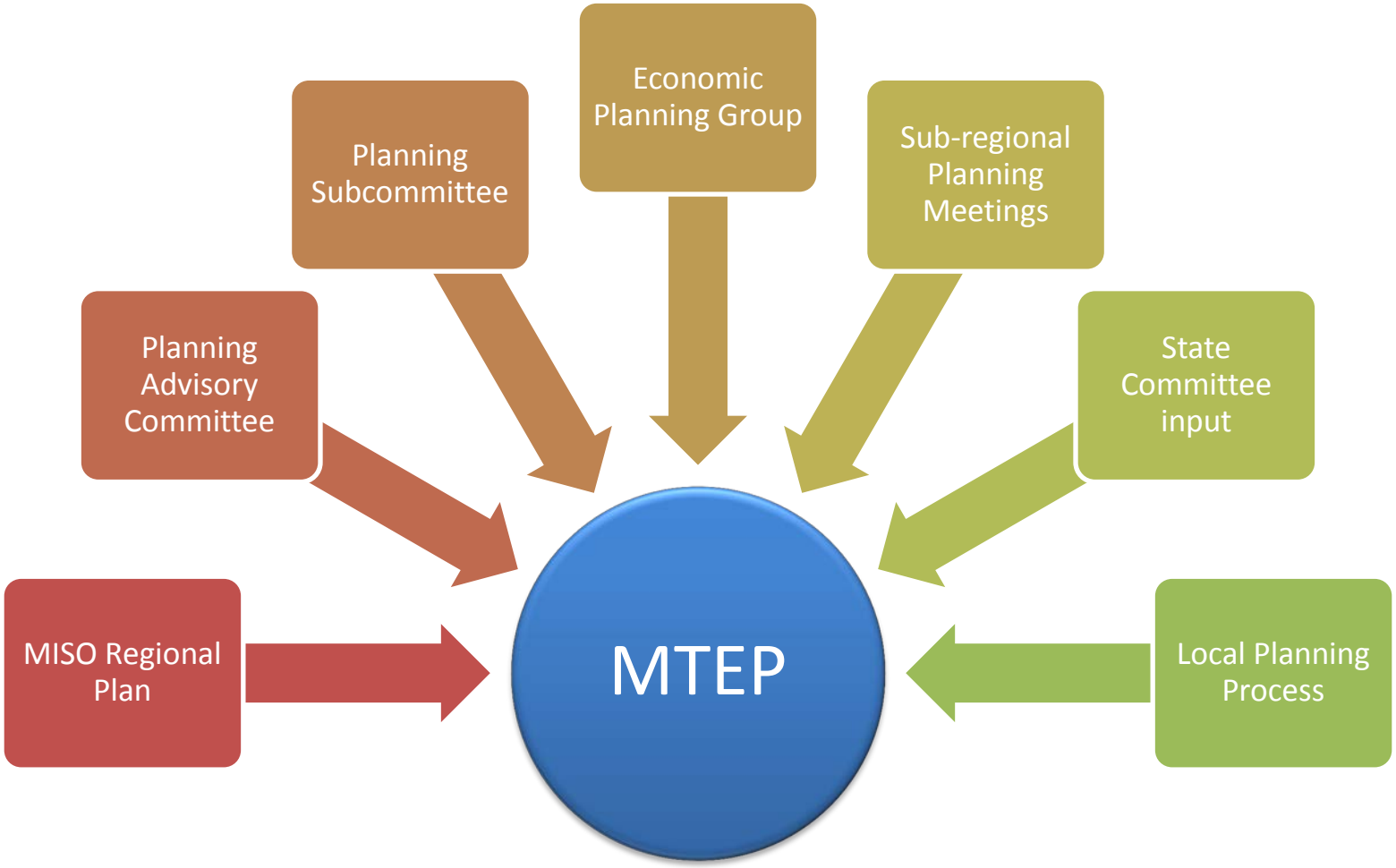
Planning Process Implementation





*Access Planning includes both the long term Transmission Service Queue and the Generator Interconnection Queue.

MISO Collaborative Planning Process



MISO South Transmission Planning

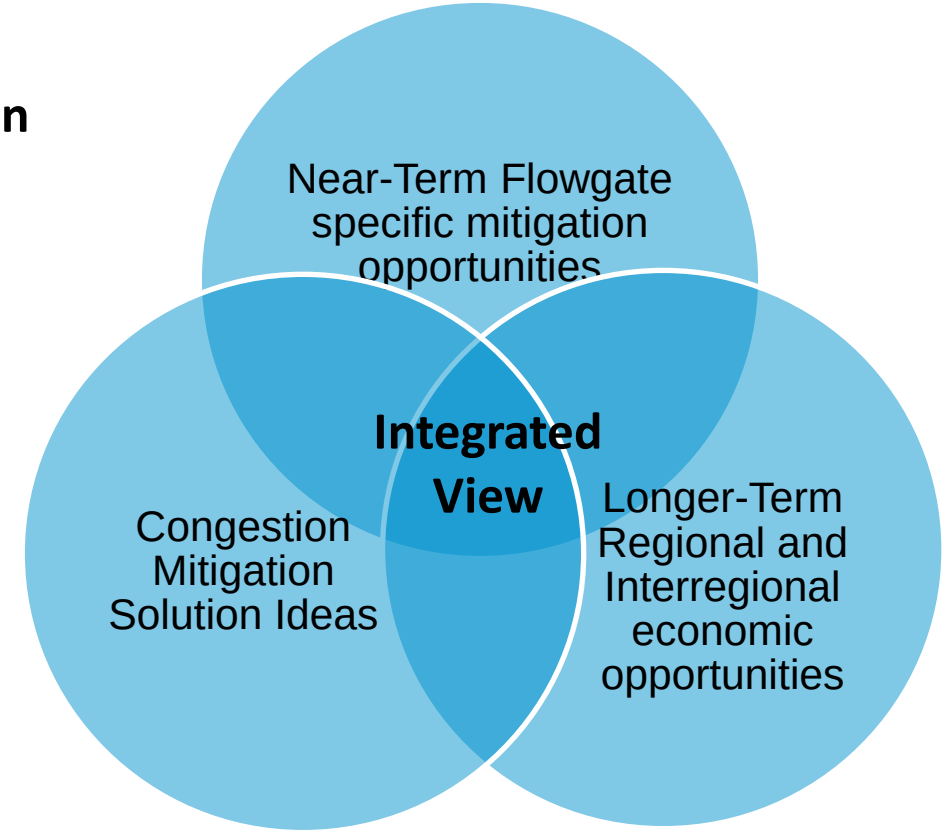
- Focus is on reliability, market efficiency, and load-pocket issues (VLR)
- More than a dozen planning meetings with Southern region stakeholders since December 2013.
- Numerous grid upgrade options have been identified through the MTEP 14 studies (83 projects / $1.8 B)
  - 69 projects ($282 M) to ensure reliability
  - 21 project candidates ($2-3 B) to reduce market congestion (includes alternatives to same issues until final selections)
- A number of these projects also help resolve load pocket issues

MTEP14 South Region Sub-Regional Planning Louisiana Project to Ensure Reliability

- 27 Louisiana projects designated for MTEP approval in the MTEP14 cycle (December 2014) - $122,250,000
- All projects within next 3 years, 25 before 2017
- Projects are driven by load growth, load additions, breaker upgrades, protection system modifications, and transmission service request
- Key Projects:
  - Projects Driven by New Load Addition, 6 new substations $72,537,000
  - Nelson 500-230 kV autotransformer upgrade, $ 21,000,000
  - Crown Zellerbach Area: New 230-138 kV Substation, $20,200,000
  - Projects Driven by Short Circuit Interrupting Capacity at 6 substations $3,051,600
  - PPG to Rose Bluff 230 kV Line upgrade $3,000,000
  - Projects Driven by Protection System Modification (SPOF Projects)- at 8 substations, $2,454,200

South Region Market Congestion Planning Study

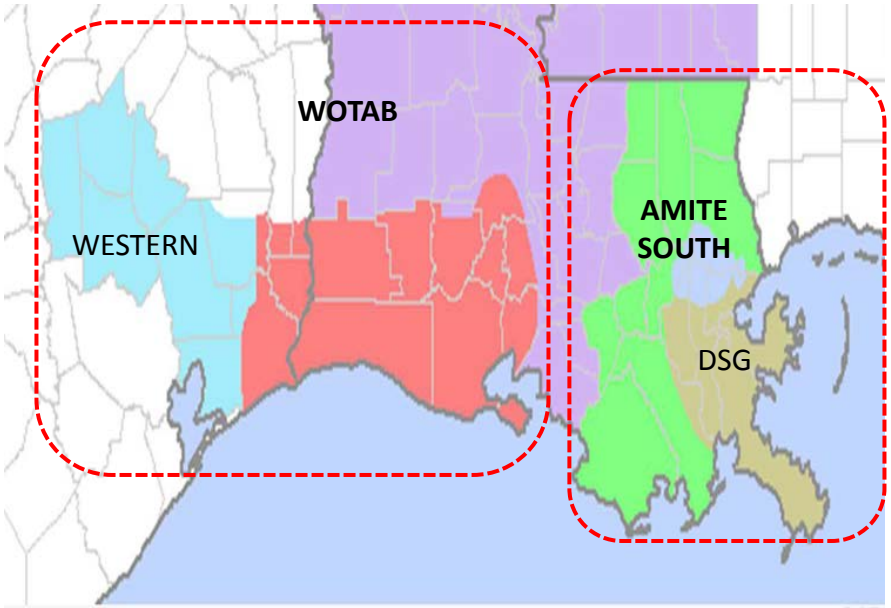
- **South region focused process to identify cost effective transmission solutions to enhance market efficiency**
- **Integrated process producing solutions linking near and longer term congestion issues**
- **Study Progress**
  - Developed South specific future scenarios to ensure robust solutions
  - Solicited and screened a total of 82 solution ideas; formulated 21 preliminary project candidates for further refinement
  - Conducted initial robustness testing against South futures and reliability assessment for selected project candidates



- **Current Status**
  - Finalizing robustness and reliability analyses
  - Initial recommendation expected December 2014; additional proposals Q2 2015

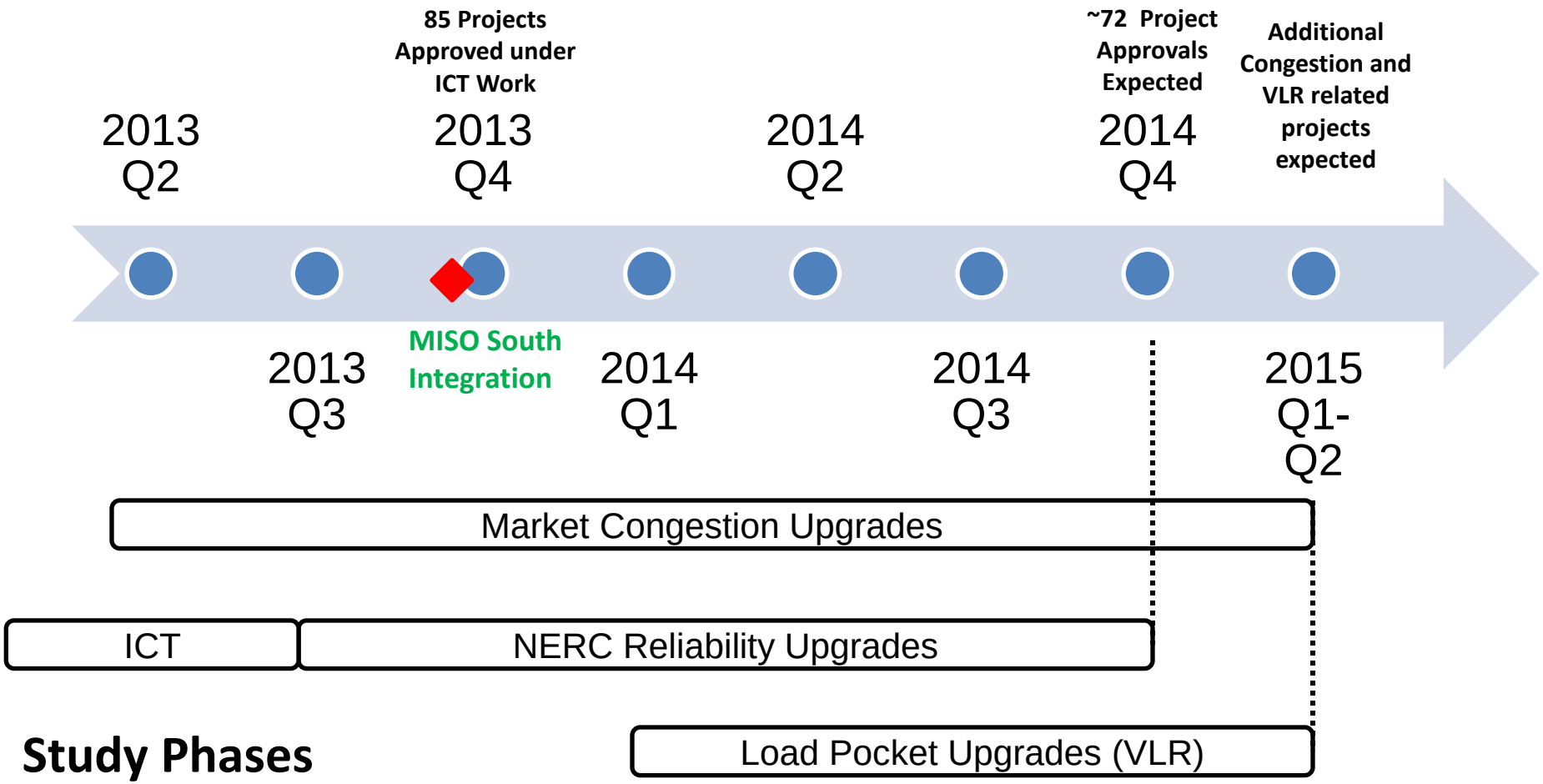
Load-Pocket (VLR) Planning

- Load-pocket issues occur when transmission limitations require reliance on local generation to ensure reliable load supply
- Local generation is committed in anticipation of contingent loss of generation or transmission serving the pocket
- MISO is studying these load pocket issues with stakeholders at the Planning Subcommittee to identify transmission upgrade options
  - Studies (prior and current) indicate that complete load pocket resolution could require substantial additional transmission (~ $2 B)
  - Determining cost-benefit and beneficiaries is important to ensuring ratepayers only pay fair shares



- Identification of solution options expected by year end – with preliminary results in August
- Complete solution with costs and beneficiaries expected Q2 2015

Study Timelines



Study Phases

Benefits for Customers Resulting From MTEP Process

- As a result of the MISO Day 2 Market in the Entergy Region, economic transmission projects that previously showed insufficient benefits to ELL/EGSL customers to warrant inclusion in the transmission plan are showing strong potential benefits based on preliminary analysis.
- ELL and EGSL are actively participating in MTEP 14 and have proposed a number of reliability and economic projects for MISO consideration; they are currently providing comments on MISO's analysis, which is ongoing.
- MISO initially identified approximately 21 Preliminary Candidate Market Efficiency Projects ("MEPs") based on initial analysis and has now narrowed that list based on further analysis to determine the projects that provide production cost savings in excess of their costs
  - Included on MISO's current list of projects are 230 kV projects in Louisiana that appear to provide substantial net benefits to the Companies' customers.
  - The MISO Day 2 Market mechanisms are a key driver of the benefits for these projects; prior to MISO, the Companies' customers could not realize savings associated with making efficient merchant gas generation deliverable unless a bilateral contract was in place with that generation.
  - In the MISO Day 2 Market, the Companies' customers are able to realize benefits from such projects irrespective of any bilateral contract; as long as the generator is able to deliver more energy, the Day 2 Market assures that the Companies' customers will receive the benefits.
- The Companies will continue to participate actively in the MTEP process in an effort to identify those projects providing the benefits described above.

Technical Conference Agenda

- Locational Marginal Price (LMP)
- Auction Revenue Rights (ARR) and Financial Transmission Rights (FTR)
- Resource Adequacy
- Transmission Planning
- **Communications for Emergency Conditions**
- Value Proposition

NERC Functional Model

Standards and Compliance Functions

Standards Development	Compliance Enforcement	Reliability Assurance
Standards Developer	Compliance Enforcement Authority	Reliability Assurer

Reliability Service Functions

Operating Reliability	Transmission Service	Planning Reliability
Reliability Coordinator	Transmission Service Provider	Planning Coordinator

Interchange	Balancing
Interchange Coordinator	Balancing Authority

Market Operations
Market Operator

Planning and Operating Functions

Transmission Ownership	Generator Operations	Transmission Operations	Transmission Planning	Resource Planning
Transmission Owner	Generator Operator	Transmission Operator	Transmission Planner	Resource Planner

Generator Ownership	Load Serving	Purchasing-Selling	Distribution
Generator Owner	Load-Serving Entity	Purchasing-Selling Entity	Distribution Provider

NERC Functions & MISO Real-Time Operations

Standards and Compliance Functions

Standards Development	Compliance Enforcement	Reliability Assurance
Standards Developer	Compliance Enforcement Authority	Reliability Assurer

Reliability Service Functions

Operating Reliability	Transmission Service	Planning Reliability
Reliability Coordinator	Transmission Service Provider	Planning Coordinator

Interchange	Balancing
Interchange Coordinator	Balancing Authority

Market Operations
Market Operator

Planning and Operating Functions

Transmission Ownership	Generator Operations	Transmission Operations	Transmission Planning	Resource Planning
Transmission Owner	Generator Operator	Transmission Operator	Transmission Planner	Resource Planner

Generator Ownership	Load Serving	Purchasing-Selling	Distribution
Generator Owner	Load-Serving Entity	Purchasing-Selling Entity	Distribution Provider

MISO's Real-Time Operations Functions

Reliability Coordinator

- Monitors Bulk Electric System with tools, processes and procedures to prevent or mitigate emergency operating situations
- Enable calculation of Interconnection Reliability Operating Limits (IROLs), and to operate within such limits

MISO Protocols for Load Shed Events

- Transmission Emergency Procedure
  - (RTO-EOP-004)
  - https://www.misoenergy.org/Library/Repository/Procedure/RTO-EOP-004-r14.1%20Transmission%20Emergencies%20Procedure.pdf
- Purpose of EOP-004
  - Criteria for declaration of transmission system emergencies
  - List of potential mitigating actions
  - Communications expectations

Interconnection Reliability Operating Limit (IROL)

- Definition (from NERC glossary)
  - A System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or Cascading Outages that adversely impact the reliability of the Bulk Electric System
- Mitigation
  - IROL conditions must be mitigated as soon as possible, but no longer than 30 minutes

Transmission System Emergencies

- Transmission System Emergencies (TSEs) are conditions that:
  - Have the potential to exceed or would exceed a known IROL or
  - Must be temporarily treated in real-time as an IROL due to system conditions

Mitigating Actions

- Implement applicable Operating Guides
- Implement emergency re-dispatch
- Start emergency-only (AME) generation and/or utilize emergency dispatch ranges
- Re-configure the transmission system
- Curtail non-firm loads
- Shed firm load if necessary
- Take other immediate actions

Emergency Response Matrix

MISO and State Official 24 X 7 Communication – Initiation of Protocol

- If there is a projection of, or actual loss of load that may undermine public health, safety and welfare this communication protocol will be initiated.
- MISO will activate an Emergency Notification to the appropriate State Officials via text, email and/or phone to the 24x7 State Official Emergency contacts making them aware that conditions warrant their attention and that further information will be provided via phone conference.
- This includes:
  - Capacity Emergency requiring firm load curtailments.
  - Transmission Emergency requiring firm load curtailments.
  - Forced Transmission outages resulting in loss of firm load.
  - Severe risk of terrorist attack, man-made or natural disaster is imminent that has potential for loss of firm load.

Emergency Response Matrix

When We Communicate

How We Communicate

What We Communicate

When We Communicate

- Conservative Operations Declaration
- Severe Weather Alert
- Minimum Generation Alert
- Maximum Generation Alert
- Maximum Generation Warning
- Maximum Generation Event

How We Communicate

Conservative Operations Declaration

Severe Weather Alert

Minimum Generation Alert

Maximum Generation Alert

Maximum Generation Warning

- Message Sent to Identified State/Local Emergency Contacts
- Message Posted on MISO Website
- Email sent to Real-Time Market mailing list

What We Communicate

Conservative Operations Declaration

Severe Weather Alert

Minimum Generation Alert*

Maximum Generation Alert*

Maximum Generation Warning*

Start/End Time

Impacted Region

Impacted Entities

Situational Instructions

*Reason for Alert

How We Communicate

Maximum Generation Event

Step 1
All available resources in use

- Message Sent to Identified State/Local Emergency Contacts
- Message Posted on MISO Website
- Email sent to Real-Time Market mailing list
- **Regional Director, or designee, contacts previously selected State/Local leaders**

** Possibility of an outage*

How We Communicate

Maximum Generation Event

Steps 2 – 5*

- Message Sent to Identified State/Local Emergency Contacts
- Message Posted on MISO Website
- Email sent to Real-Time Market mailing list
- **Regional Director, or designee, contacts previously selected State/Local leaders**
- **Corporate Communications contacts utility counterpart**

** Load Shed*

What We Communicate

Maximum Generation Event

Step 1
All available resources in use

Start/End Time

Impacted Region

Impacted Entities

Situational Instructions

Reason for Alert

Estimated Number of MWs

What We Communicate

Maximum Generation Event

Steps 2 – 5*

Start/End Time
Impacted Region
Impacted Entities
Situational Instructions
Reason for Alert
Estimated Numbers of MWs

May be able to provide:

Cause(s) Leading to Directive

Activities Undertaken to Correct Outage

** Load Shed*

What Utilities Communicate

Maximum Generation Event

Steps 2 – 5*

Number of MWs (Estimated for Step 1)

Number of Customers Affected

Likely Duration of Outage

Possible Safety/Health Concerns

Preliminary Cause of Outage

Activities to Correct Outage

** Load Shed*

How We Communicate

Alert/Event Termination

- Message Sent to Identified State/Local Emergency Contacts
- Message Posted on MISO Website
- Email sent to Real-Time Market mailing list
- Corporate Communications contacts utility counterpart
- Regional Director, or designee, contacts previously selected State/Local leaders

What We Communicate

Alert/Event Termination

- End Time
- Impacted Region
- Impacted Entities
- Reason for Alert Termination
- Situational Instructions
- Number of MWs Restored

May be able to provide

- Cause(s) Leading to Directive
- Activities Taken to Correct Outage
- Likelihood of Another Event in Near Future Due to Same or Related Causes

What Utilities Communicate

Alert/Event Termination

- Time When First Customer is Restored
- Time When Last Customer is Restored
- Unique Lingering Health or Safety Concerns for Customers
- Likelihood of Another Event in the Near Future Due to Same or Related Causes

Technical Conference Agenda

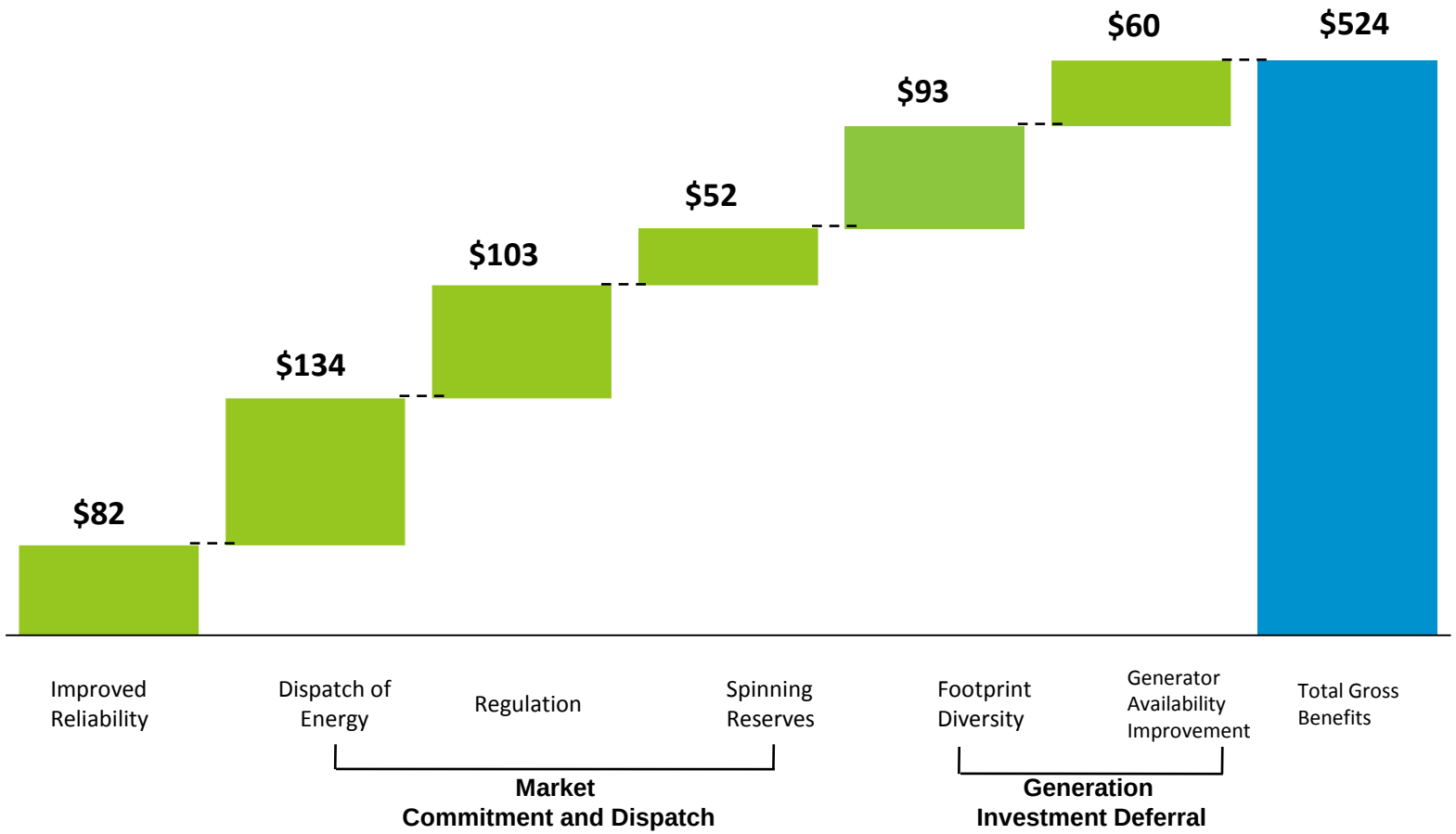
- Locational Marginal Price (LMP)
- Auction Revenue Rights (ARR) and Financial Transmission Rights (FTR)
- Resource Adequacy
- Transmission Planning
- Communications for Emergency Conditions
- **Value Proposition**

MISO Value Proposition Basics and Timelines

- MISO's standard Value Proposition is an annual, historic review of economic benefits to the footprint
  - Does not allocate benefits to specific entities
    - Actual recipient of the economic benefits varies by benefit and also based on the retail rate structure in place
- MISO applied this same methodology to estimate the potential future benefits associated with the integration of the Entergy Operating Companies into MISO
  - MISO will complete a full Value Proposition update for the footprint – available in first quarter 2015
- MISO has conducted an interim review
  - Compared key assumptions made in forward-looking estimate against actual performance to date
  - For those benefits categories for which information is currently available, performance is better than originally forecast

Original 2010 Estimate of Annual Benefits from Addition of Entergy Operating Companies[1]

Preliminary in $ millions



Transmission planning/construction works to increase value in virtually every benefit category

[1] Estimated $105 million of benefits will flow to MISO members existing prior to Entergy Integration

Regulation Benefit

Pre-Integration Requirement

MISO	400 MW
Entergy	267 – 450 MW
Remainder of South Region	Unknown

Forecast Requirement Post-Integration

MISO – entire footprint	445 MW

Actual Post-Integration Performance

MISO – entire footprint	400 MW

Benefits

- Significant reduction in requirement
- Requirement held at top of generation stack
- More economic capacity made available for energy dispatch

Spinning Reserves Benefit

Pre-Integration Requirement

MISO	935 MW
Entergy	271 – 306 MW
Remainder of South Region	Unknown

Forecasted Requirement Post-Integration

MISO – entire footprint	1,003 MW

Actual Post-Integration Performance

MISO – entire footprint	935 MW

Benefits

- Significant reduction in requirement
- Requirement held at top of generation stack
- More economic capacity made available for energy dispatch

Footprint Diversity Benefit

Pre-Integration Requirement

Entergy	26,008 MW

Forecasted Requirement Post-Integration

Entergy	25,004 MW
	1,004 MW reduction

Actual Post-Integration Requirement

Entergy	23,896 MW
	2,112 MW reduction

Benefits:

- Significant reduction in generation requirement
- Excess capacity available for sale
- Reduced need for future capacity additions

Summary

- MISO will complete a full 2014 Value Proposition for the entire footprint – available in first quarter 2015

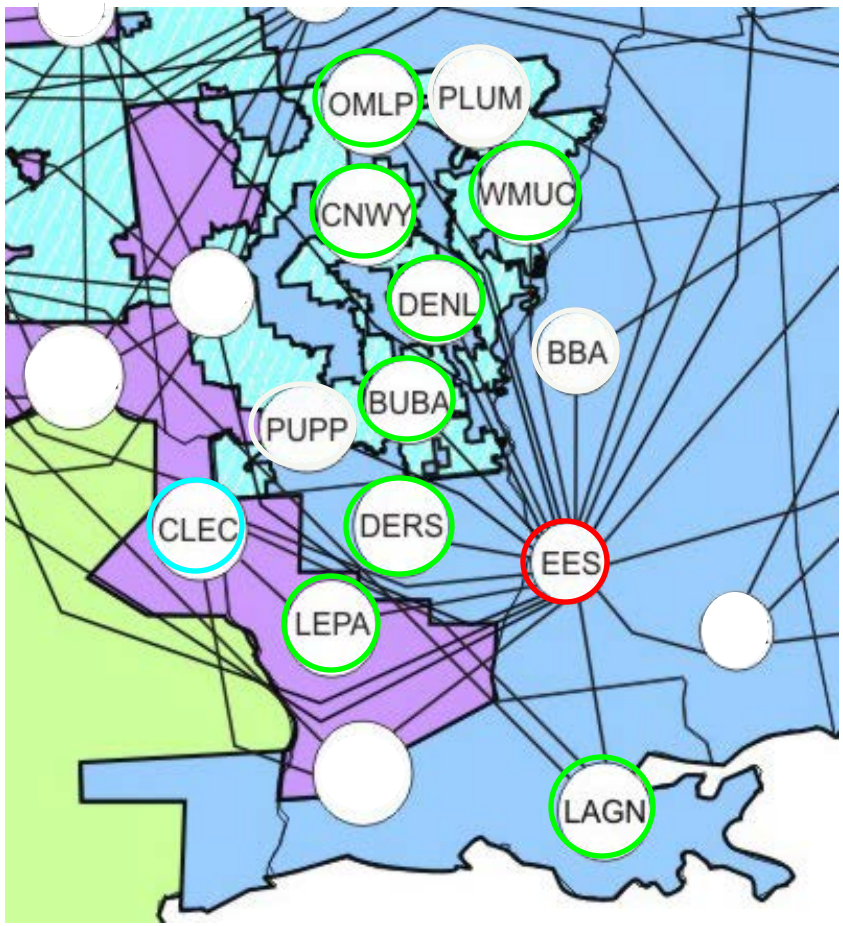
- MISO's interim review indicates that performance on several items is better than originally estimated:

	Forecast Improvement	Actual Improvement
Regulation	33% - 48%	40% - 53%
Spinning Reserves	17% - 19%	22% - 25%
Footprint Diversity	3.5%	8.1%

Entergy Footprint Has Multiple Decision Makers

Can't "find" optimal dispatch

NERC Balancing Authorities Prior to MISO



Excerpt from NERC map, Regions and Balancing Authorities, Feb 12, 2010

- Entergy
- Cleco
- Other – generation and/or load
- Other – generation only

Prior to MISO – Multiple Decision Makers Without Systematic Coordination

- 8 load-serving entities that commit and dispatch generation for their own load
- ~40 qualified facilities that decide whether to run their units and "put" to Entergy
- ~15 independent power producers who make independent decisions on commitment and dispatch when they sell to customers outside of the Entergy region (i.e., SPP, SoCo, TVA, MISO)
- 13 balancing authorities

Why the MISO Day 2 Market Makes a Difference

- Before MISO there was no coordinated generation dispatch in the Entergy footprint:
  - Entergy committed its units; Cleco committed its units; IPPs made their own decisions based on their view of markets and availability of transmission
  - OATT transmission service was "use it or lose it"
  - Each participant's actions could affect others – and cause a suboptimal result

- In MISO's Day 2 market:
  - One central unit of commitment and dispatch instructions, based on economics of generation and transmission – more efficient
  - Participants are free to make their own decisions, but the effect will be reflected in LMPs – if you create congestion, you pay for it
  - Transmission rights are now financial rather than physical
  - Vertically integrated utilities can run their own units when that is lower cost and buy from the market when that is lower cost

Benefits Realized to Date for Customers

- Displaced Legacy Generation
  - While the Companies' MISO market experience is limited to six months, we have seen some reduction in output from legacy gas generation.
    - Flexible capability requirement is reduced and can be provided by all units in MISO.
    - Pre-MISO voltage support largely had to come from our units; now it can come from non-Entergy units in MISO.

- QFs Are Participating in the Market
  - Most large QFs have registered as Market Participants and are selling their energy directly to MISO and receiving payment.
  - This means a reduction in the need for "flexible capability" to address unscheduled puts.

- Lower Planning Reserve Margin
  - The larger MISO region allows for a lower reserve margin, therefore requiring that the Companies obtain less capacity. The decrease in capacity costs is a direct benefit to customers.
  - The capacity needs of ELL & EGSL have decreased by 254 MW because of MISO participation.

- We are in the process of developing possible methodologies for measuring long term benefits and costs.

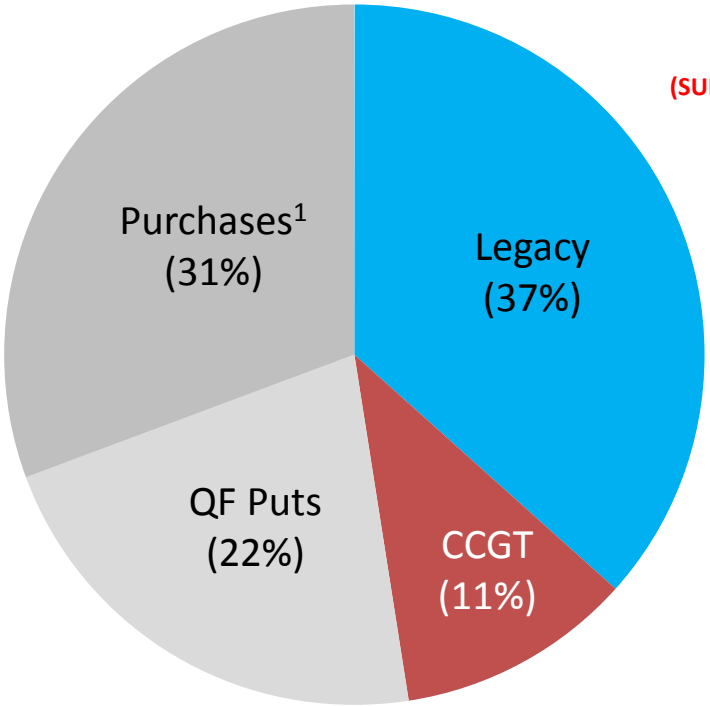
PRELIMINARY EVIDENCE POINTS TO FUEL AND PURCHASED POWER SAVINGS

- Key Components of ELL/EGSL's Predicted Energy-Related Savings in MISO

NON-BASELOAD RESOURCES

BEFORE MISO

(12/19-6/30 Over Previous 3 Years)

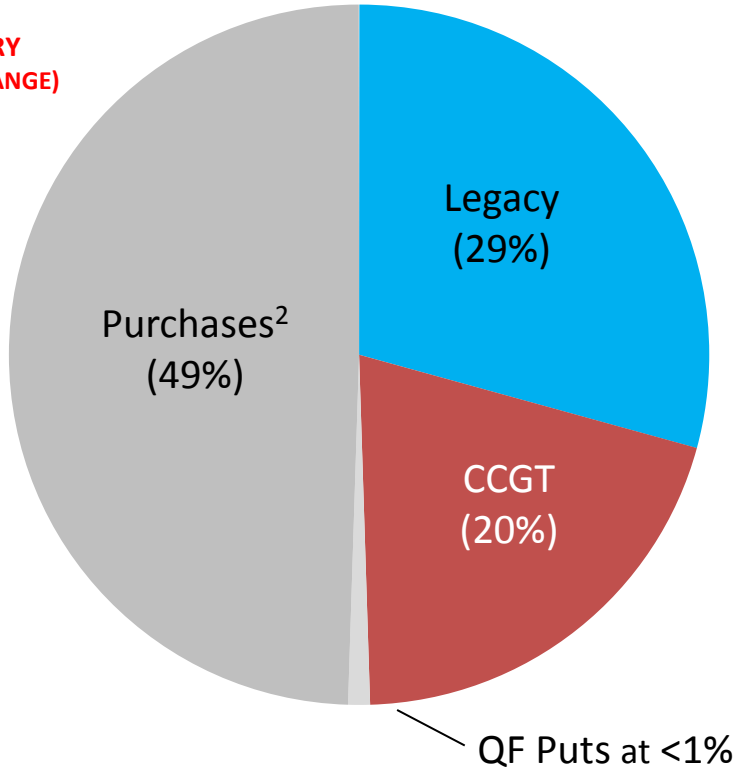


PRELIMINARY
(SUBJECT TO CHANGE)

NON-BASELOAD RESOURCES

IN MISO

(12/19/13-6/30/14)



[1] Purchases from others, including QFs.

[2] Purchases from Market Participants, including QFs.

Factors Affecting FAC Charges

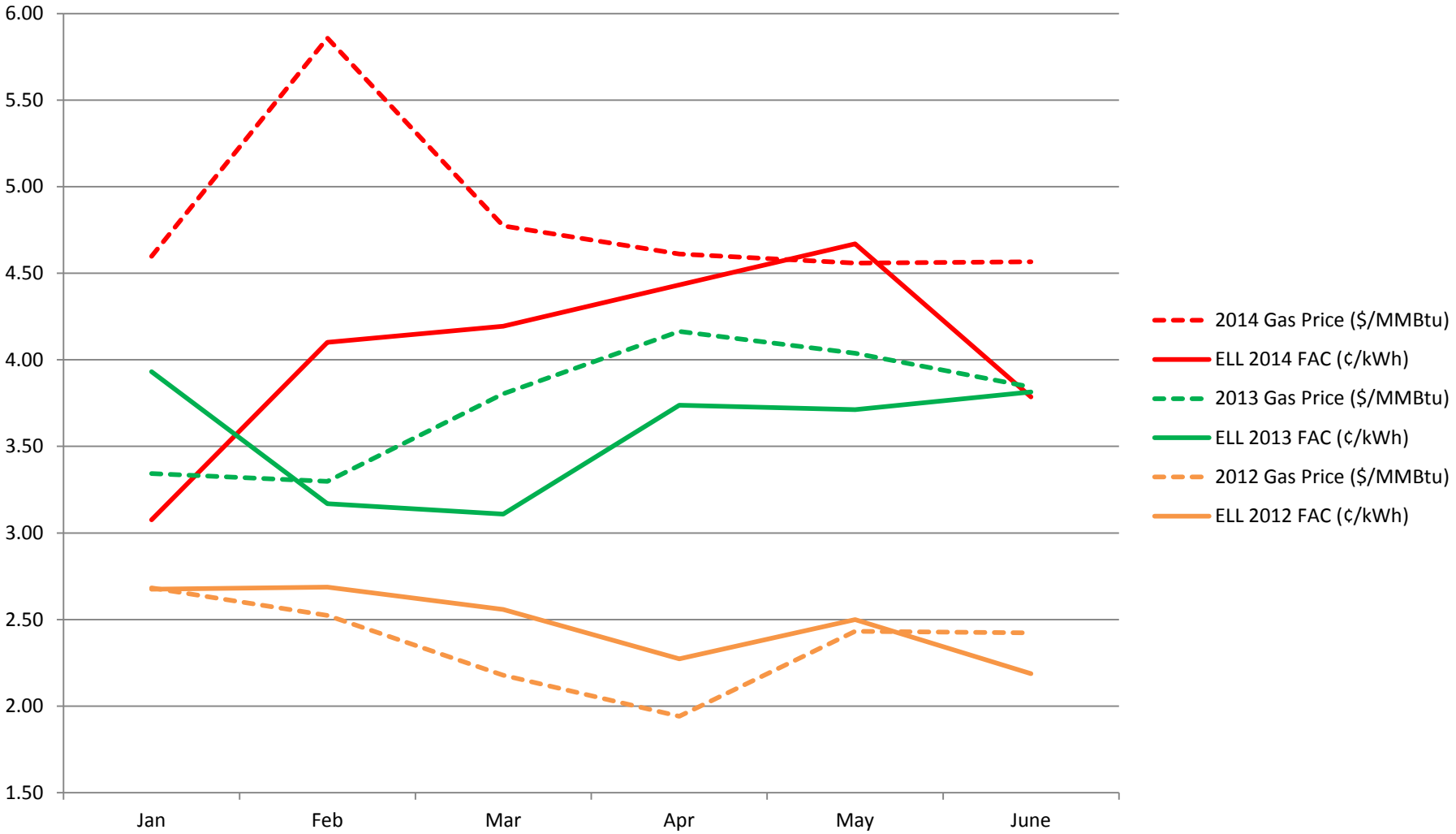
- Gas prices have increased substantially in 2014:

	2014 Average Henry Hub Gas Price ($/MMBtu)	2013 Average Henry Hub Gas Price ($/MMBtu)	Percent Increase
Jan	4.60	3.34	38%
Feb	5.86	3.30	78%
Mar	4.77	3.80	25%
Apr	4.61	4.16	11%
May	4.56	4.04	13%
June	4.57	3.84	19%

- Generation outages:
  - Waterford 3 refueling outage from April 13, 2014 through May 14, 2014.
  - Nelson 6 outage from April 24, 2014 through June 11, 2014.
  - Perryville outage from April 1, 2014 through April 25, 2014.

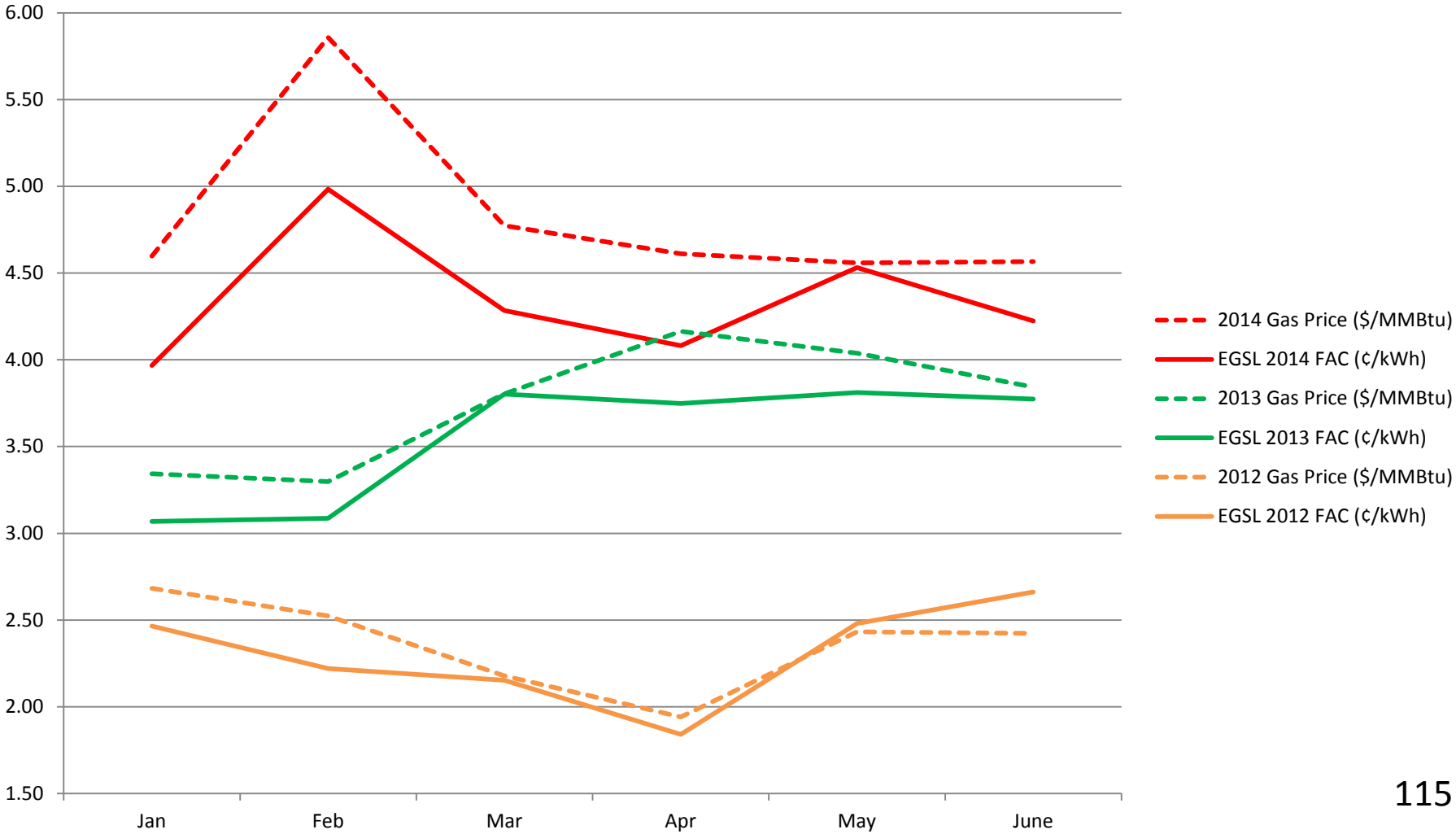
ELL January-June FAC Charges For Last Three Years

- Gas prices have increased in 2014 and have affected FAC charges



EGSL January-June FAC Charges For Last Three Years

- Gas prices have increased in 2014 and have affected FAC charges



LMPs Compared to the FAC Charge

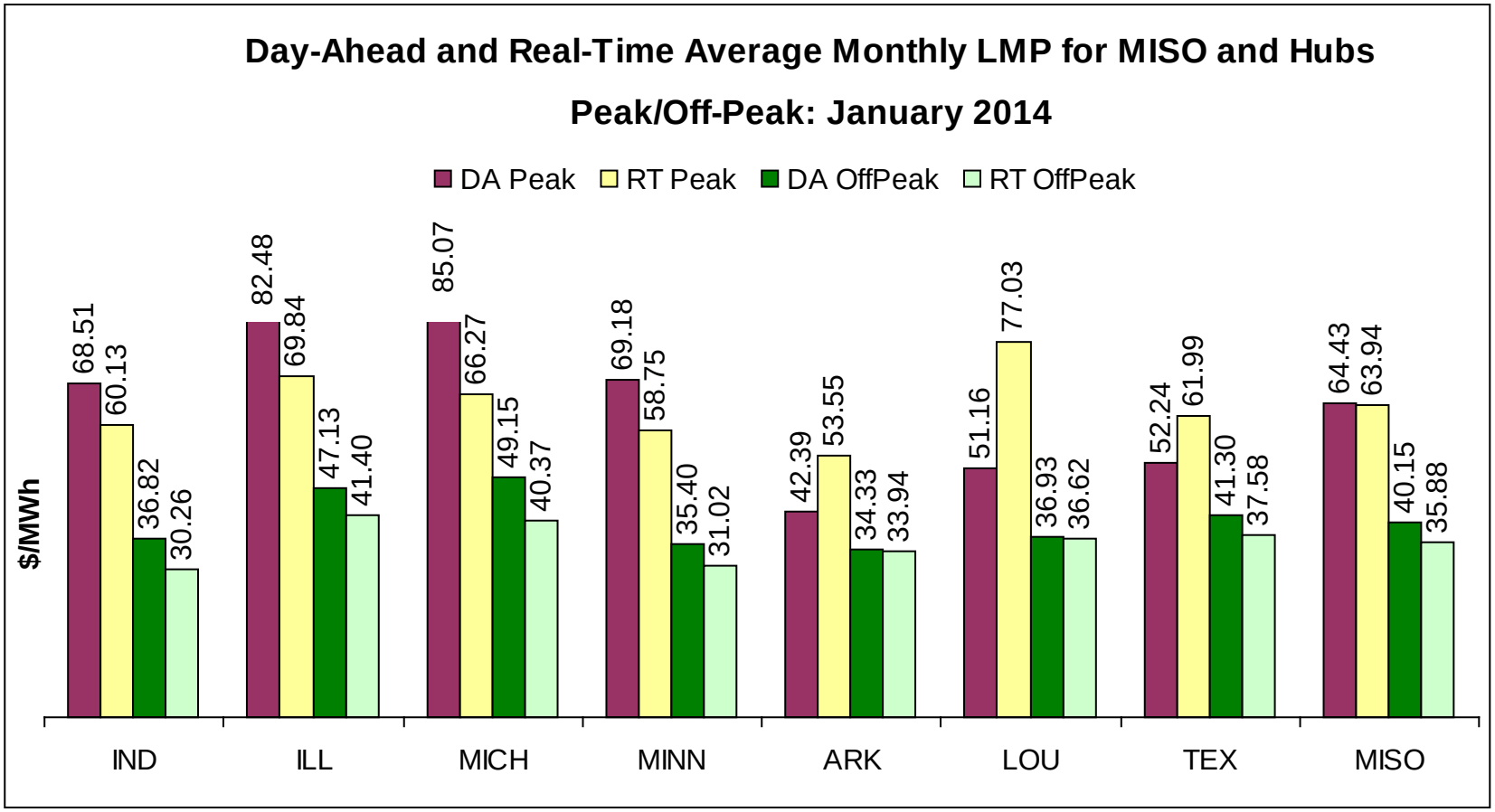
- To show that customer costs do not equal LMPs, we compared:
  - Average Generator bus LMPs received by EGSL and ELL generation
  - Average Load zone LMPs paid by EGSL and ELL
  - Actual Fuel Adjustment Clause charges for the same periods
- FAC charges are consistently less than the LMPs:

	EGSL			ELL		
	Generator Bus LMPs	Avg. Load Zone LMP	Avg. FAC Charge	Generator Bus LMPs	Avg. Load Zone LMP	Avg. FAC Charge
Jan. 2014	47.03	47.30	39.68	42.85	45.37	30.76
Feb. 2014	53.61	56.09	49.84	52.45	55.02	41.01
Mar. 2014	43.46	46.63	42.84	43.53	48.07	41.94
Apr. 2014	48.32	49.92	40.81	44.89	47.21	44.33
May 2014	59.96	56.45	45.31	41.78	45.91	46.70
June 2014	48.37	49.37	42.24	40.28	43.76	37.87

Generator Bus LMP is the average LMP price paid to the Companies' generators in both day ahead and real time.
LMPs in this table reflect the average of all LMPs during the time period.
FAC figures shown reflect the month in which costs are incurred, not the month in which costs are billed.

Appendix

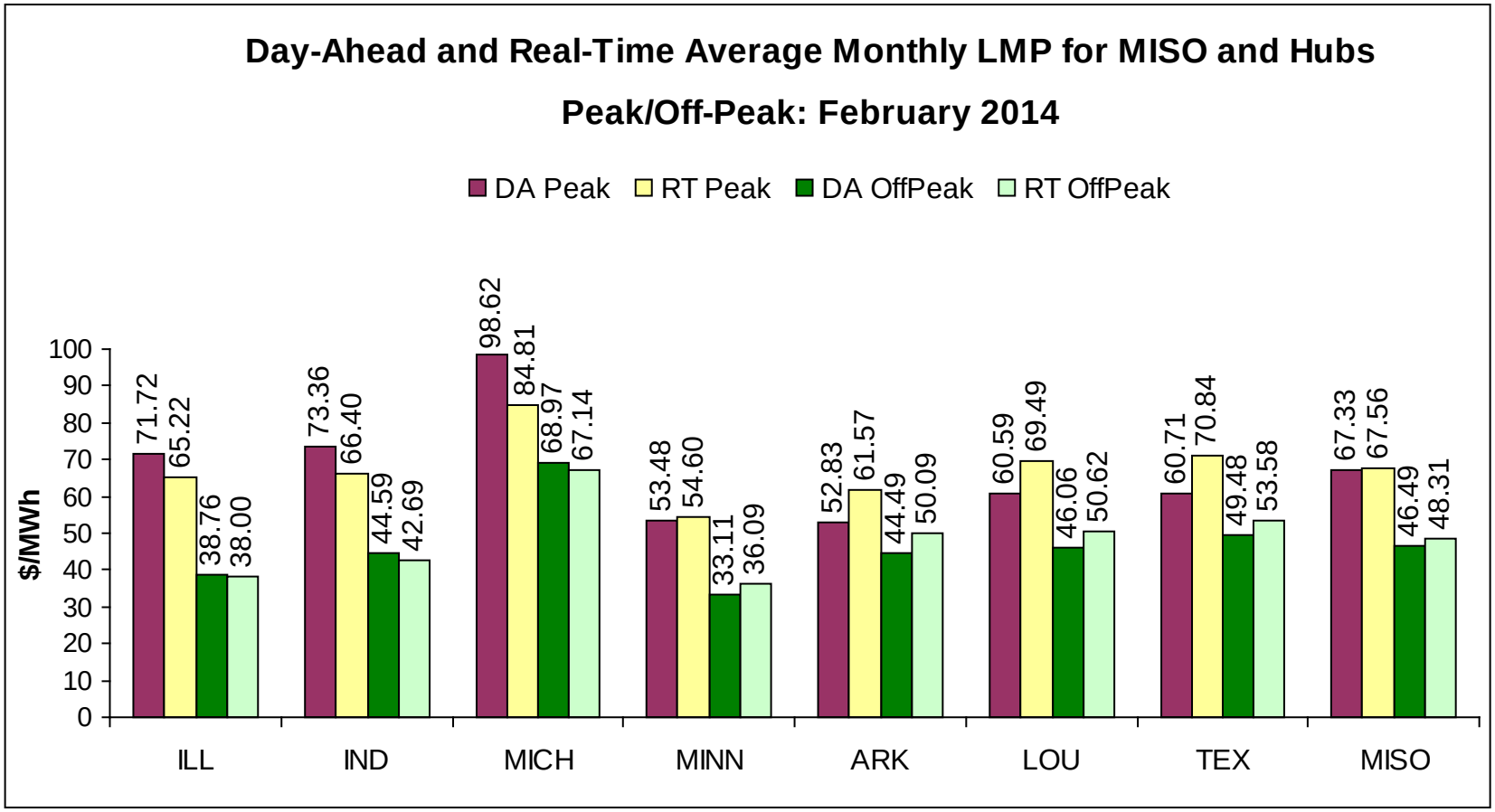
Pricing



		IND	ILL	MICH	MINN	ARK	LOU	TEX	MISO
Congestion Component of LMP ($/MWh)	DA Peak	2.15	12.98	14.79	-0.62	-23.13	-15.28	-13.38	-3.21
	RT Peak	-3.20	3.13	-0.90	-5.76	-8.19	13.32	-0.88	-0.35
	DA OffPeak	-1.90	6.51	7.72	-4.75	-4.42	-2.74	1.85	0.32
	RT OffPeak	-4.13	5.00	3.51	-4.04	-0.28	1.30	2.23	0.51

Source: MISO Information Delivery and Market Analysis Department

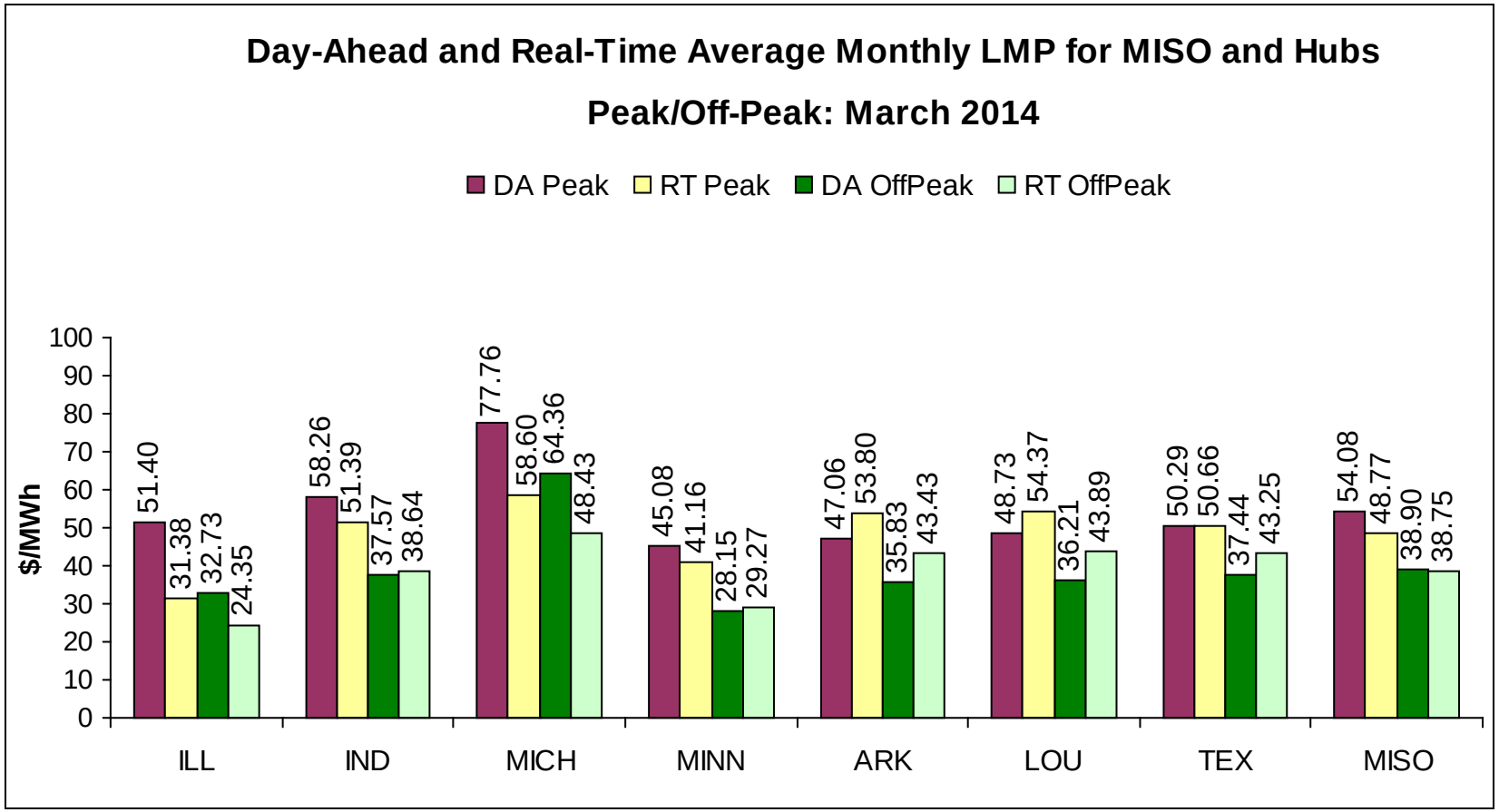
Pricing



		ILL	IND	MICH	MINN	ARK	LOU	TEX	MISO
Congestion Component of LMP ($/MWh)	DA Peak	3.29	1.78	25.54	-18.24	-14.30	-8.07	-8.23	-2.60
	RT Peak	-2.28	-3.13	12.62	-13.86	-4.76	1.79	2.05	-1.08
	DA OffPeak	-5.94	-2.19	21.02	-13.65	-0.19	0.47	3.26	0.40
	RT OffPeak	-8.53	-5.46	17.35	-11.66	3.56	3.32	4.83	0.49

Source: MISO Information Delivery and Market Analysis Department

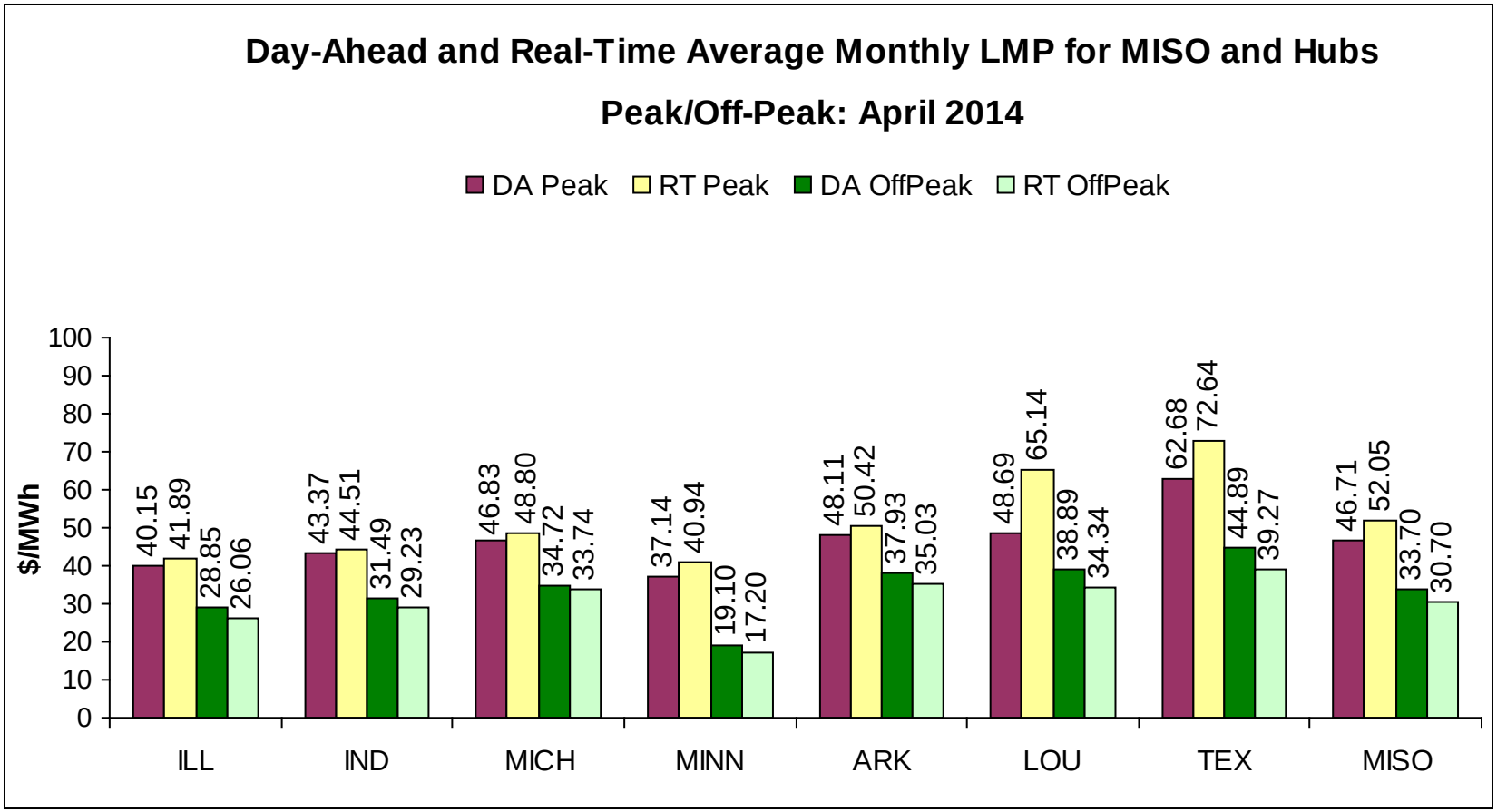
Pricing



		ILL	IND	MICH	MINN	ARK	LOU	TEX	MISO
Congestion Component of LMP ($/MWh)	DA Peak	-3.57	1.61	18.30	-10.44	-7.47	-6.93	-5.65	-2.02
	RT Peak	-18.46	-0.39	4.43	-8.59	4.55	3.56	-0.14	-2.15
	DA OffPeak	-5.25	-1.66	23.55	-10.46	-2.11	-2.72	-1.96	-0.08
	RT OffPeak	-12.83	-0.06	8.16	-8.43	6.37	5.90	5.13	0.60

Source: MISO Information Delivery and Market Analysis Department

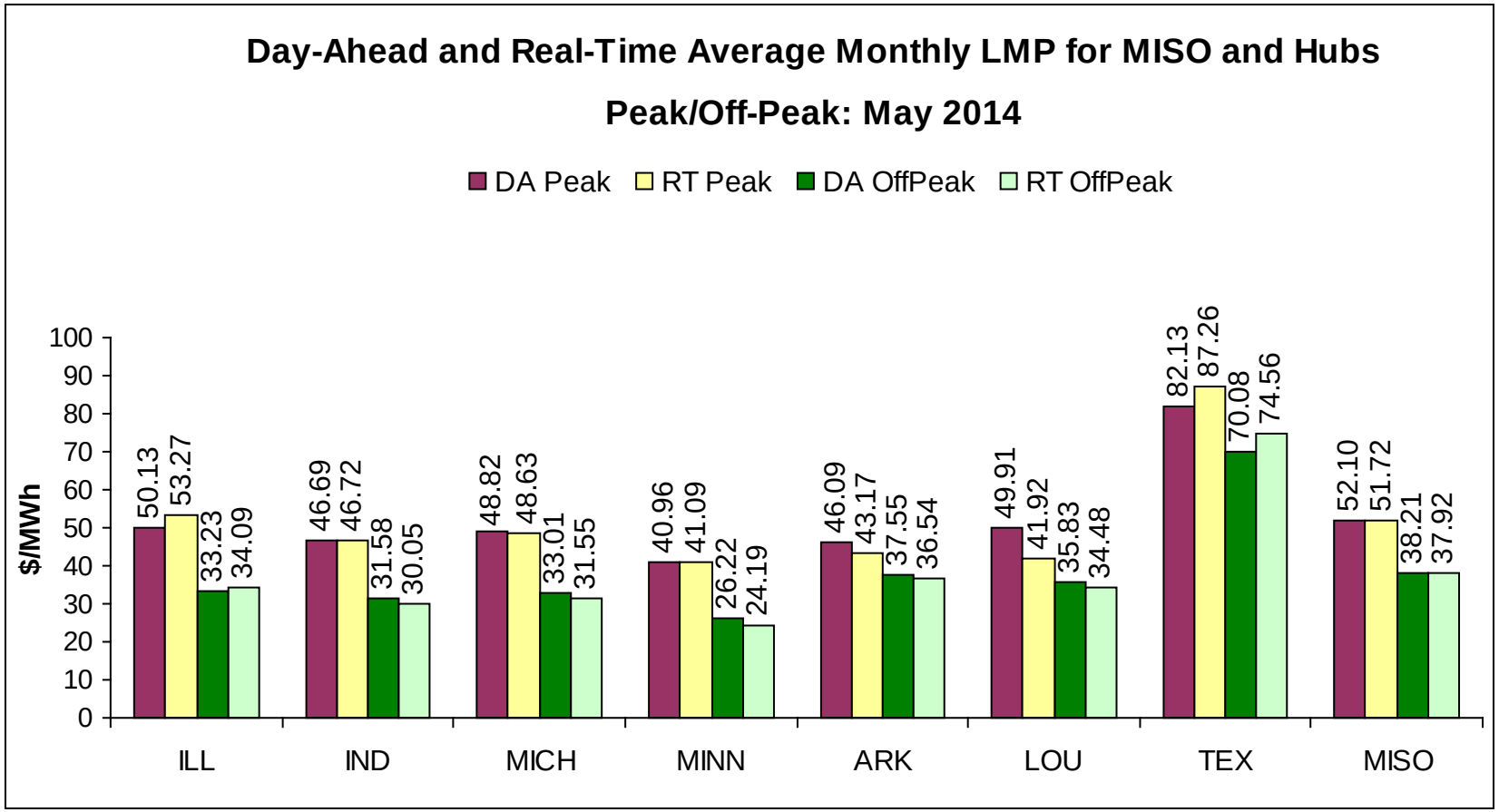
Pricing



		ILL	IND	MICH	MINN	ARK	LOU	TEX	MISO
Congestion Component of LMP ($/MWh)	DA Peak	-2.09	-0.65	1.02	-5.26	5.43	4.25	18.32	3.00
	RT Peak	-4.19	-3.25	-1.00	-6.39	4.53	17.86	25.12	4.67
	DA OffPeak	0.16	1.52	3.96	-9.59	8.87	9.02	14.94	4.12
	RT OffPeak	-0.36	1.74	5.18	-9.02	8.51	6.93	11.58	3.51

Source: MISO Information Delivery and Market Analysis Department

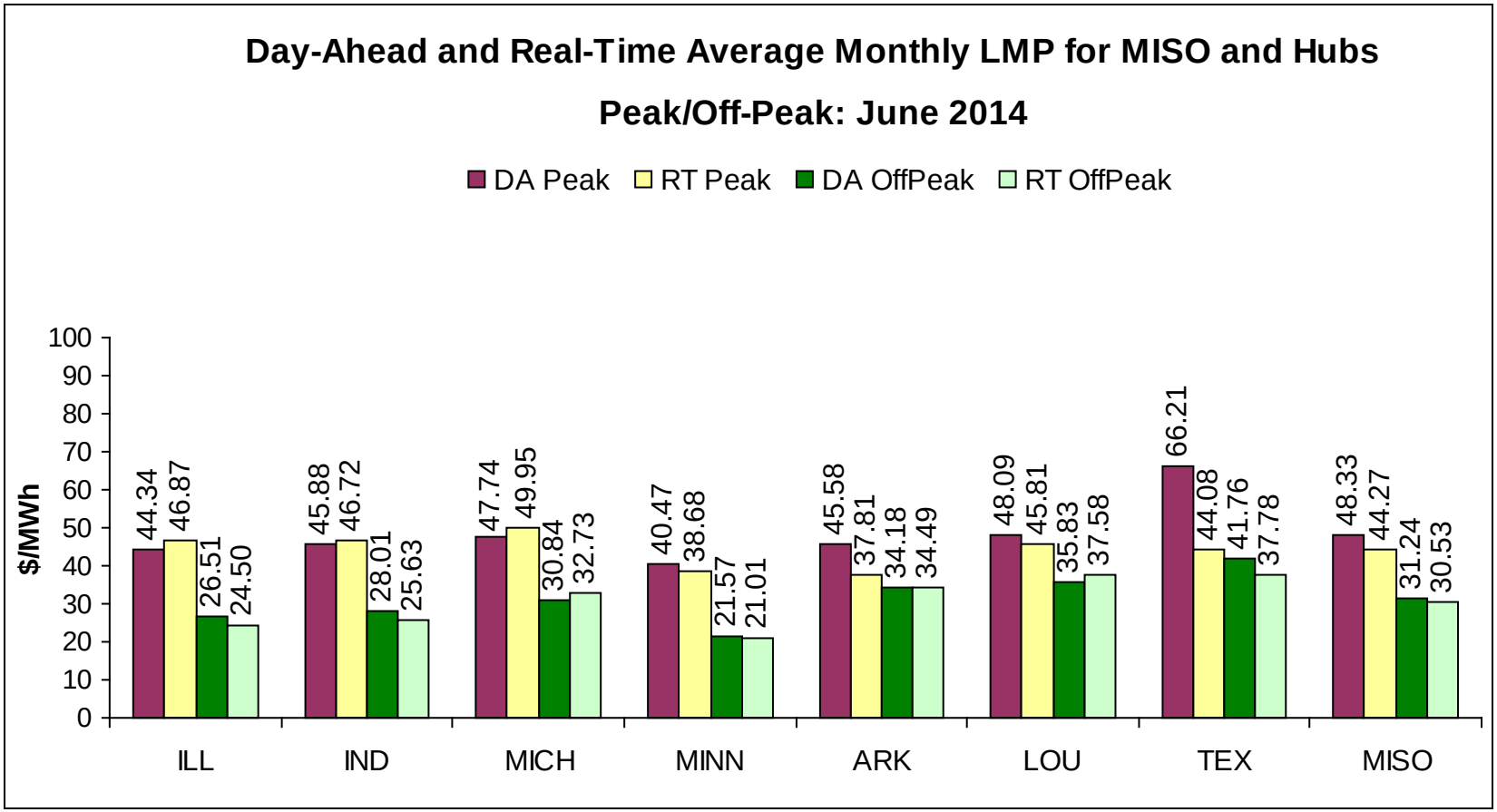
Pricing



		ILL	IND	MICH	MINN	ARK	LOU	TEX	MISO
Congestion Component of LMP ($/MWh)	DA Peak	3.10	-2.28	-2.34	-5.53	-1.03	1.49	33.51	3.85
	RT Peak	4.70	-2.61	-1.89	-6.34	-3.54	-6.04	38.16	3.21
	DA OffPeak	1.69	-1.25	-0.75	-5.52	5.72	3.03	37.14	5.72
	RT OffPeak	2.97	-1.82	-1.16	-6.03	5.79	2.85	41.92	6.36

Source: MISO Information Delivery and Market Analysis Department

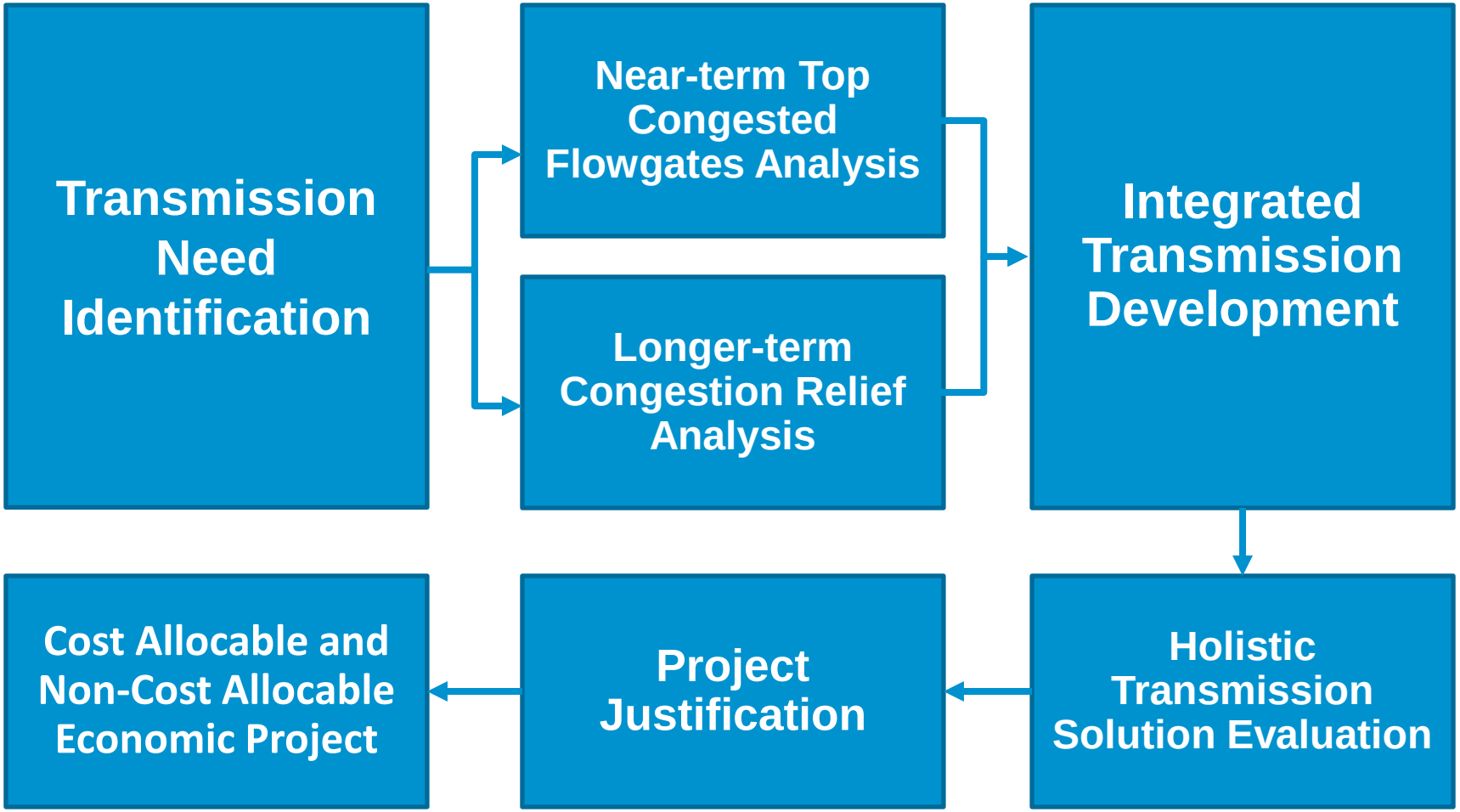
Pricing



		ILL	IND	MICH	MINN	ARK	LOU	TEX	MISO
Congestion Component of LMP ($/MWh)	DA Peak	-1.10	-0.59	-0.22	-3.71	1.82	2.27	19.85	2.62
	RT Peak	2.61	1.09	2.86	-4.55	-5.12	0.59	-1.22	-0.54
	DA OffPeak	-0.41	0.28	2.21	-4.79	7.73	7.99	13.49	3.79
	RT OffPeak	-1.01	-0.77	5.60	-3.58	9.22	10.96	11.03	4.49

Source: MISO Information Delivery and Market Analysis Department

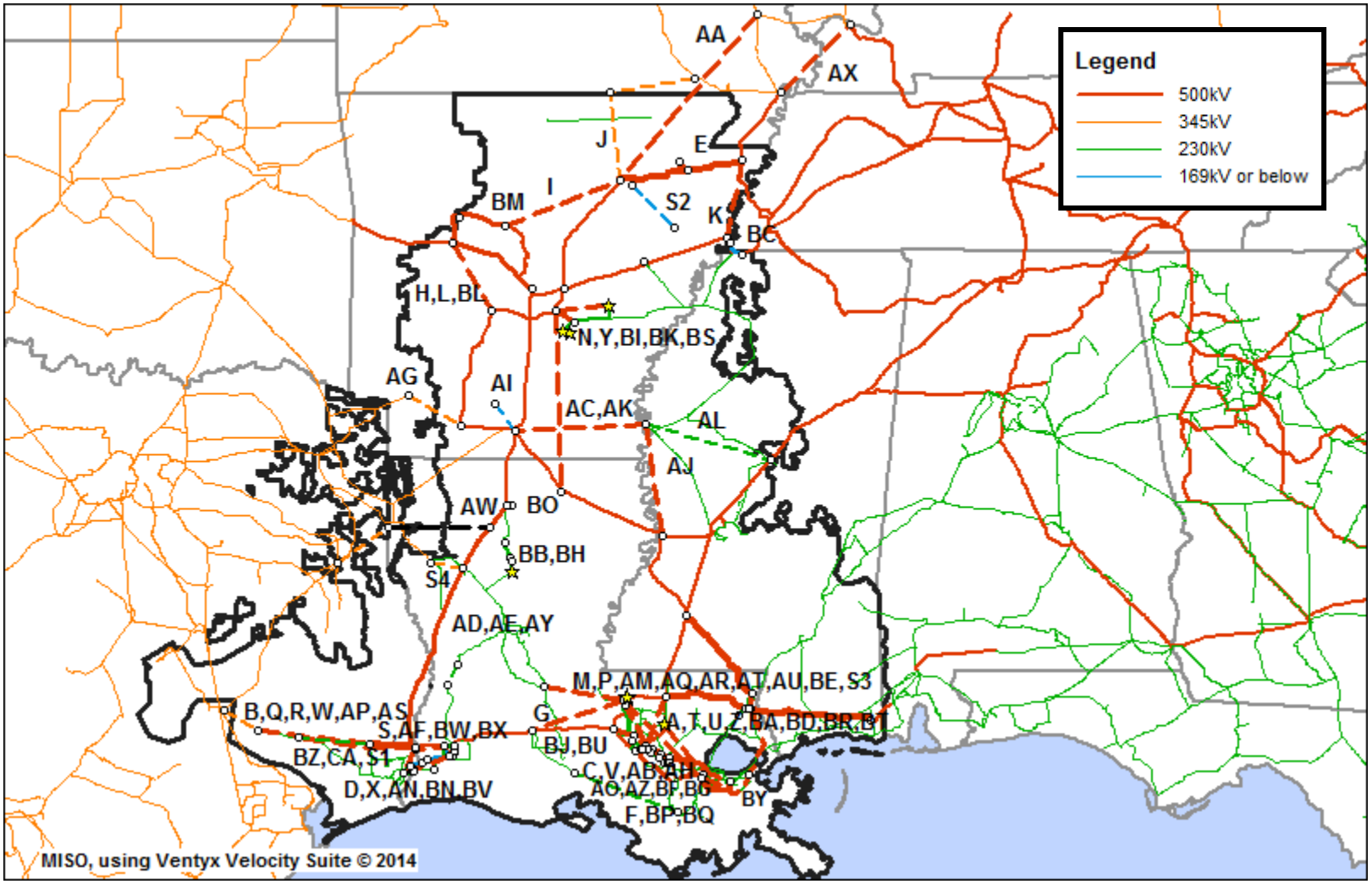
MISO South Market Congestion Planning Process



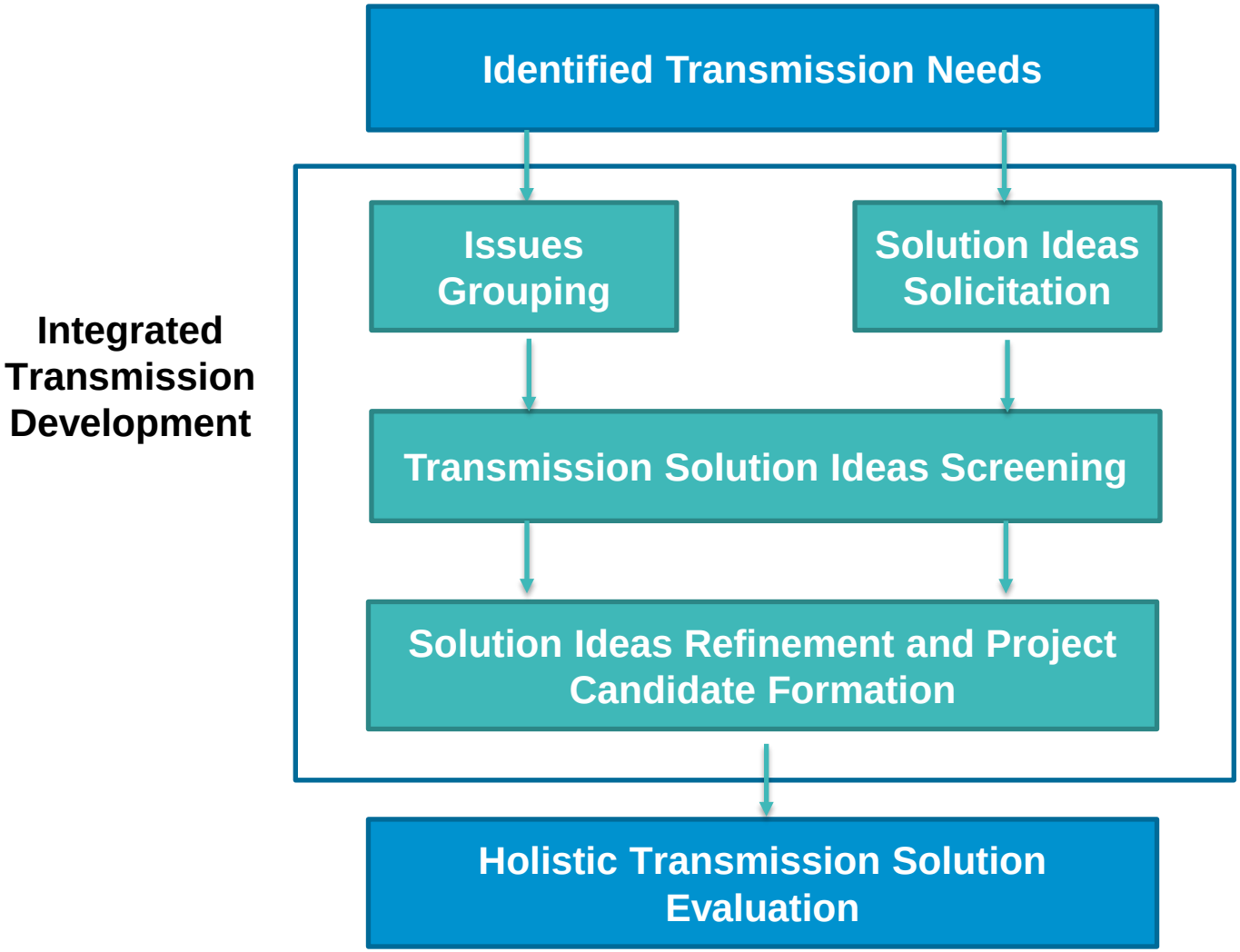
MISO South MCPS Progress

	Work Efforts	Status	Detailed Progress
Need Identification	Historical Congestion Analysis		Historical top TLR/LAP selected
	Near-term Top Congested Flowgate Analysis		Refreshed top congested flowgates identified
	Long-term Congestion Relief Analysis		Refreshed Economic opportunities identified on zonal/regional levels
Transmission Development and Evaluation	Transmission Solution Ideas Solicitation		Solicited transmission solution ideas for the all Futures
	Transmission Screening Process		Completed transmission screening process for the all the solution ideas
	Economic Analysis		Performed initial robustness testing on project candidates
	Reliability Analysis		Performed initial reliability analysis on project candidates

82 Proposed Transmission Solution Ideas to Address the Identified Needs within the South region



Integrated Transmission Development and Evaluation Process



Holistic Transmission Development and Evaluation

- **An iterative process to ensure most efficient and cost effective solutions to be identified to address the needs**
  - Start with a preliminary screening process to inform the feasibility of transmission options prior to detailed economic analysis
  - Refine transmission solution ideas guided by preliminary screening results and formulate project candidates to better align with identified needs
  - Refine project candidates and further test against a broad set of MTEP futures to ensure robustness
  - Conduct reliability assessment for selected project candidates to ensure system reliability is maintained
- **A total of 82 solution ideas considered and 21 preliminary project candidates selected for robustness & reliability testing**

Summary of Preliminary Project Candidates by Issue

ID	Project Candidate Description	State	Issues Addressed	MISO Independent Cost Estimate ($M-2013)	APC Savings ($M-2028)	One-year Weighted B/C Ratio
PC_A	Dow Meter – Iberville 230kV	LA	A	39.93	44.04	5.92
PC_B	Waterford – Nine Mile 500kV*	LA	B	149.68	3.66 – 53.19	0.13 – 1.94
PC_C	Fancy Point – Willow Glen 500kV	LA	A,L	188.72	32.48	0.97
PC_D	Big Cajun - Willow Glen 500 kV	LA	A,L	222.57	29.17	0.67
PC_E	Big Cajun - Richard 500kV	LA	A	268.10	36.41	0.63
PC_F	Nelson - Mossville 138kV	LA	Z,AA	12.50	10.14	4.10
PC_G	Upgrade Cow - Colonial Orange - Gully Bunch - Orange 138kV	TX	D	9.16	4.14	6.00
PC_H	Cow 230-138kV XMFR	TX	D,AA	16.80	3.89	1.31
PC_I	ERCOT HVDC Interconnection	LA/TX	Y	500.00	141.01	1.52
PC_J	Upgrade ANO - Pleasant Hill 500kV Terminal Equipment	AR	E	0.60	7.12	67.27
PC_K	Convert Danville - Dodson - Jeld Wen - Winnfield to 230kV	LA	U	4.00	1.29	1.76
PC_L	Bogalusa – Bogue Chitto – Michoud 500kV*	LA	A,B,L,AK	391.80	35.82 – 116.17	0.40 – 1.34
PC_M	Bagatelle - Sunshine 230kV & Sunshine – Panama 230kV	LA	B	20.50	15.37	4.00
PC_N	DOW - Iberville 230kV & Bagatelle - Sunshine 230kV & Sunshine - Panama 230kV	LA	A,B	60.43	62.25	5.51
PC_O	DOW - Iberville 230kV & Waterford – Nine Mile 500kV*	LA	A,B	189.61	57.69 – 101.68	1.63 – 2.90
PC_P	Upgrade ANO – Mabelvale 500kV & ANO – Pleasant Hill 500kV Terminal Equipment	AR	E	1.20	7.54	35.64
PC_R	Waterford - Conway - Willow Glen Transmission Project	LA	B,N	43.79	9.28	1.15
PC_T	Bogalusa - Bogue Chitto – Michoud - Nine Mile - Waterford 500kV*	LA	A,B,L,AK	758.23	34.73 – 120.44	0.26 – 0.72
PC_U	Upgrade Panama - Wilton 230kV	LA	B	7.52	1.28	0.99
PC_V	NSUB - Panama 500kV	LA	B	48.57	9.75	1.08
PC_W	DOW - Iberville 230kV & Bagatelle - Sunshine 230kV & Sunshine - Panama 230kV & Coly 500/230kV XMFR	LA	A,B,L	71.49	75.27	5.62

*Added Benefits from relieving Load Pocket Commitment Guidelines

Holistic Transmission Solution Evaluation – Economic Analysis Overview

- **Goal is to review the robustness of the Project Candidates by performing a complete Economic Analysis**
  - Project Candidates were tested against all MISO South futures using the 2018, 2023 and 2028 year PROMOD models
- **Benefit to Cost ratios were calculated using the Net Present Value (NPV) Benefit for the first 20 years of project life, with a maximum planning horizon of 25 years from the approval year**
- **Weighted Benefit to Cost ratios were calculated for each Project Candidate using the MISO South future weights**

Summary of Initial Robustness Testing Results for Selected Project Candidates

Eligible for cost sharing as MEP based on voltage/cost criteria

ID	Description	State	Issues Addressed	Project Cost ($M - 2013)	B/C ratio (BAU)	B/C ratio (RE)	Weighted B/C ratio
PC_B	Waterford - Nine Mile 500kV*	LA	B, VLR	149.68	0.10 – 2.21	0.30 – 0.71	**0.16 – 1.76**
PC_L	Bogalusa - Bogue Chitto - Michoud 500kV*	LA	A,B,L,AK, VLR	391.80	0.28 – 1.60	0.73 – 1.80	**0.42 – 1.44**
PC_I	ERCOT HVDC Interconnection	LA/TX	Y	500.00	1.45	0.79	**1.25**

- **Additional coordination between MISO and ERCOT needs to occur to more thoroughly evaluate PC_I**
  - The Assumption Document for this project has been posted as supplemental meeting material
- **In the coordinated effort between the MISO South MCPS and the VLR Study PC_B and PC_L will be further considered, together with reliability solutions identified in the VLR Study**
  - Range of B/C ratios for Project Candidates represent no relief of Load Pocket VLR Commitment Operating Guides(low end numbers) and complete relief of VLR Commitment Operating Guides (high end numbers)

*Added Benefits from relieving Load Pocket Commitment Guidelines

Summary of Initial Robustness Testing Results for Selected Project Candidates (Cont.)

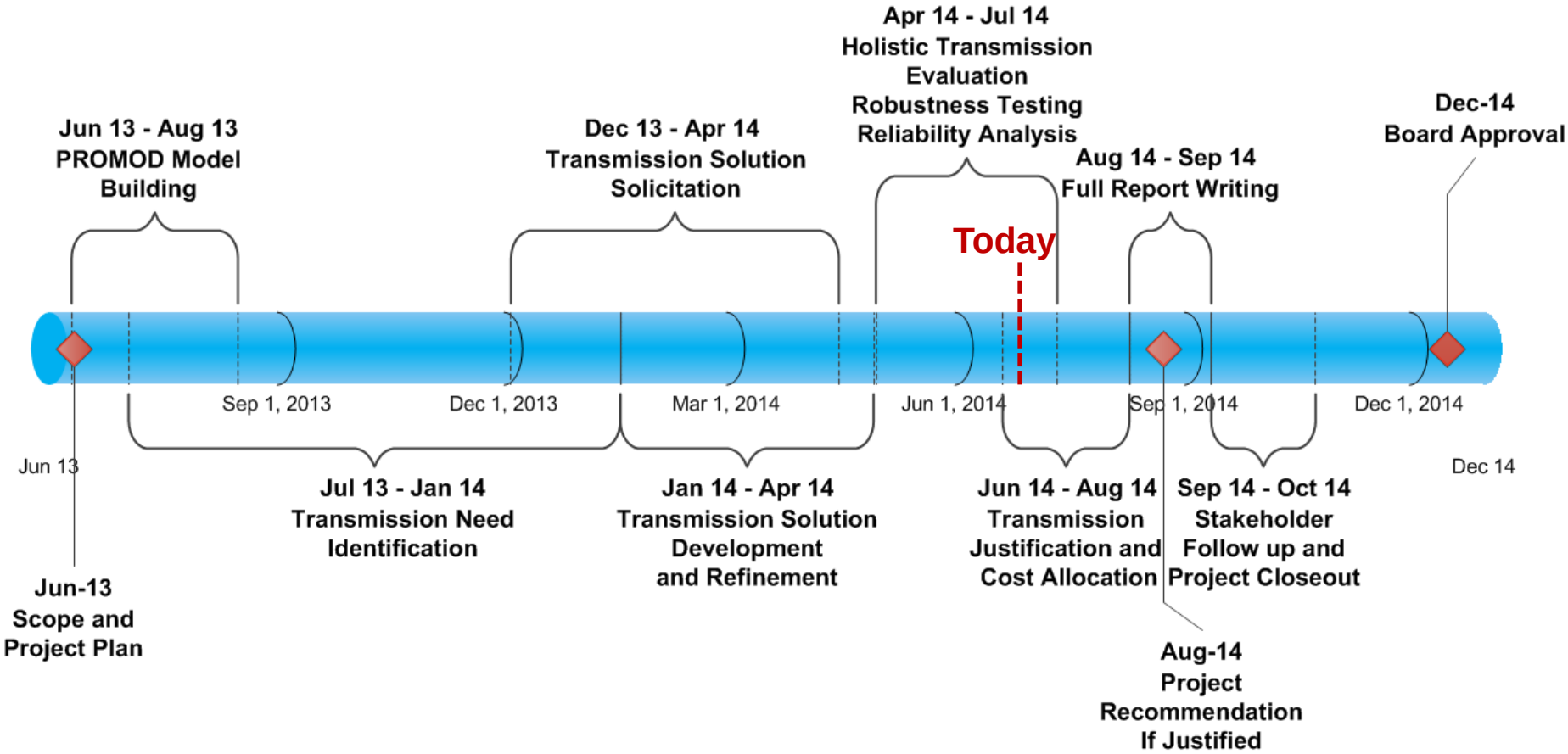
Not eligible for cost sharing as MEP based on voltage/cost criteria

ID	Description	State	Issues Addressed	Project Cost ($M - 2013)	B/C ratio (BAU)	B/C ratio (RE)	Weighted B/C ratio
PC_P	Upgrade ANO - Pleasant Hill 500kV & ANO - Mabelvale 500kV Terminal Equipment	AR	E	1.20	33.15	10.01	**26.21**
PC_A	Dow Meter - Iberville 230kV	LA	A	39.93	5.92	4.68	**5.55**
PC_W	Dow Meter - Iberville 230klV & Bagatelle - Sunshine - Panama 230kV & Coly 500/230kV XMFR	LA	A,B,L	71.49	4.68	5.35	**4.88**
PC_M	Bagatelle - Sunshine - Panama 230kV	LA	B	20.50	3.61	4.03	**3.74**
PC_F	3rd Nelson - Mossville 138kV	LA	Z,AA	12.50	0.04	11.41	**3.45**
PC_G	Upgrade Cow - Colonial Orange - Gully Bunch - Orange 138kV	TX	D	9.16	5.74	4.77	**5.45**
PC_O	Dow Meter - Iberville 230kV & Waterford - Nine Mile 500kV*	LA	A,B, VLR	189.61	1.41 – 2.93	1.49 – 1.80	**1.43 – 2.59**

- **In the coordinated effort between the MISO South MCPS and the VLR Study PC_O will be further considered, together with reliability solutions identified in the VLR Study**
- **The less cost effective alternatives to address the same issues have been removed for further analysis:**
  - PC_A appears to be most cost effective to address A, compared to PC_C, PC_D and PC_E
  - PC_M appears to be the most cost effective to address B, compared to PC_R, PC_T, PC_U and PC_V
  - PC_W appears to be most cost effective to address A&B, compared to PC_N and PC_O
  - PC_G appears to be most cost effective to address D, compared to PC_H
  - PC_P appears to be most cost effective to address E, compared to PC_J
- **PC_K does not provide a significant B/C ratio to pay for itself**

*Added Benefits from relieving Load Pocket Commitment Guidelines

MISO South Market Congestion Planning Study Indicative Timeline



Next Steps

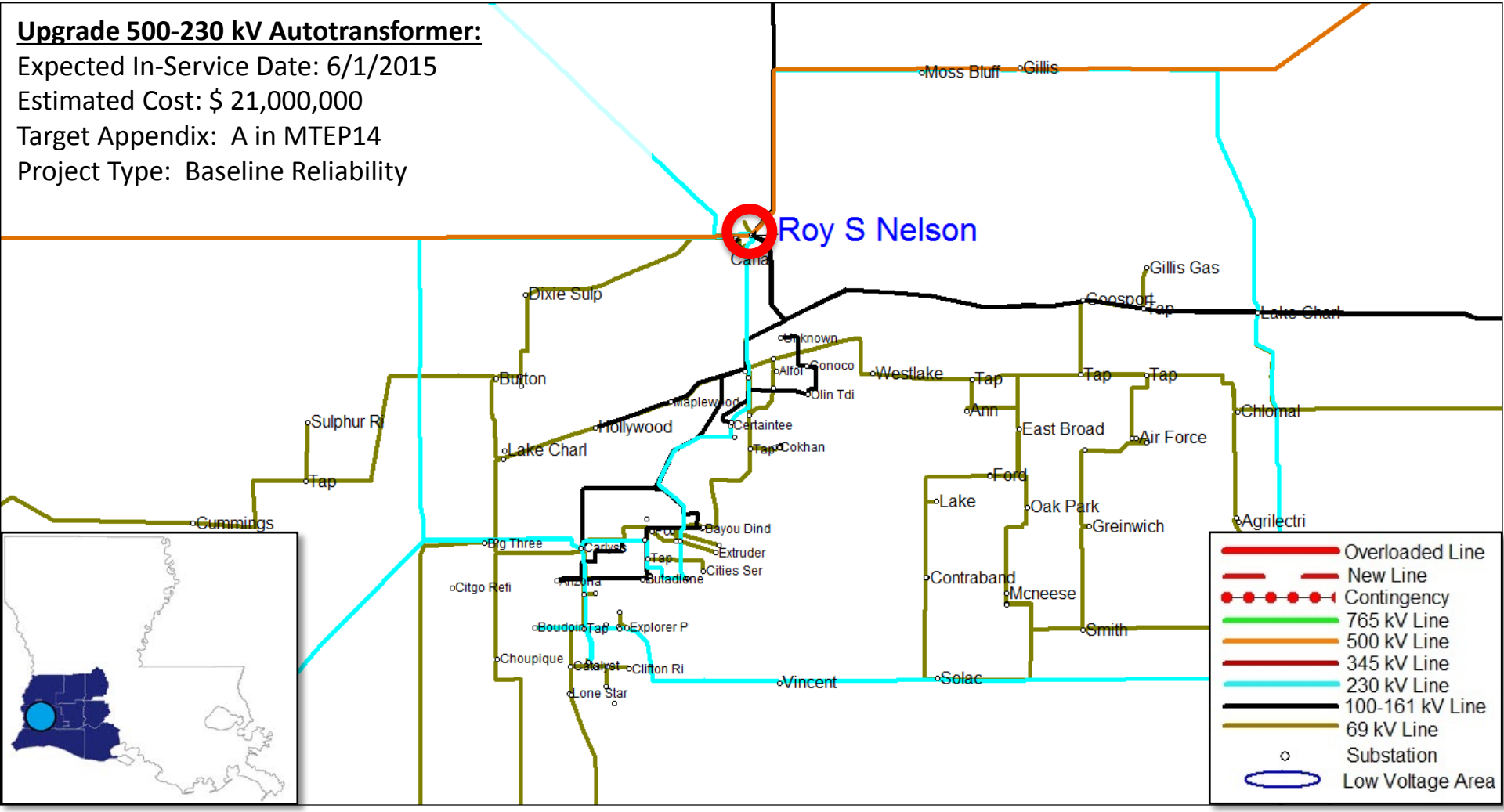
- **MISO**
  - Further refine project candidates with stakeholder feedback
  - Finalize robustness testing and reliability assessment results for the refined project candidates
- **Stakeholder**
  - Supply further refinements on project candidates based on the initial results of robustness testing and reliability analysis
  - Provide feedback on the MISO proposed transmission cost estimates
  - Responses due by August 1, 2014
- **Next meeting will be tentatively scheduled for mid-August to review final results of economic and reliability analyses**

MISO Appendix a projects

- MISO MTEP14

Nelson 500 kV Substation
P4625 (14-EGL-005)

Upgrade 500-230 kV Autotransformer:
Expected In-Service Date: 6/1/2015
Estimated Cost: $ 21,000,000
Target Appendix: A in MTEP14
Project Type: Baseline Reliability



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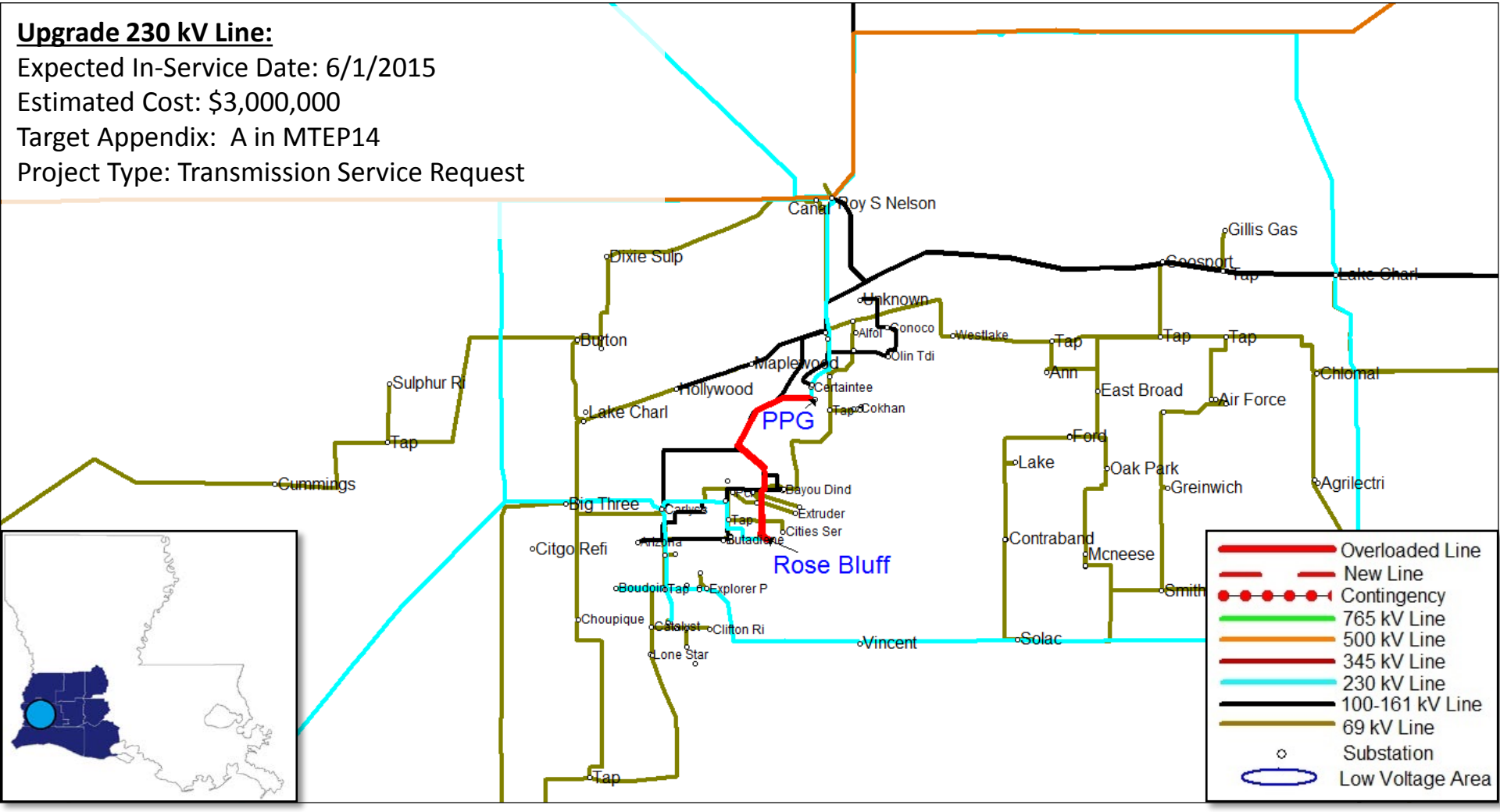
PPG to Rose Bluff 230 kV Line
P4719 (14-EGL-020)

Upgrade 230 kV Line:
Expected In-Service Date: 6/1/2015
Estimated Cost: $3,000,000
Target Appendix: A in MTEP14
Project Type: Transmission Service Request



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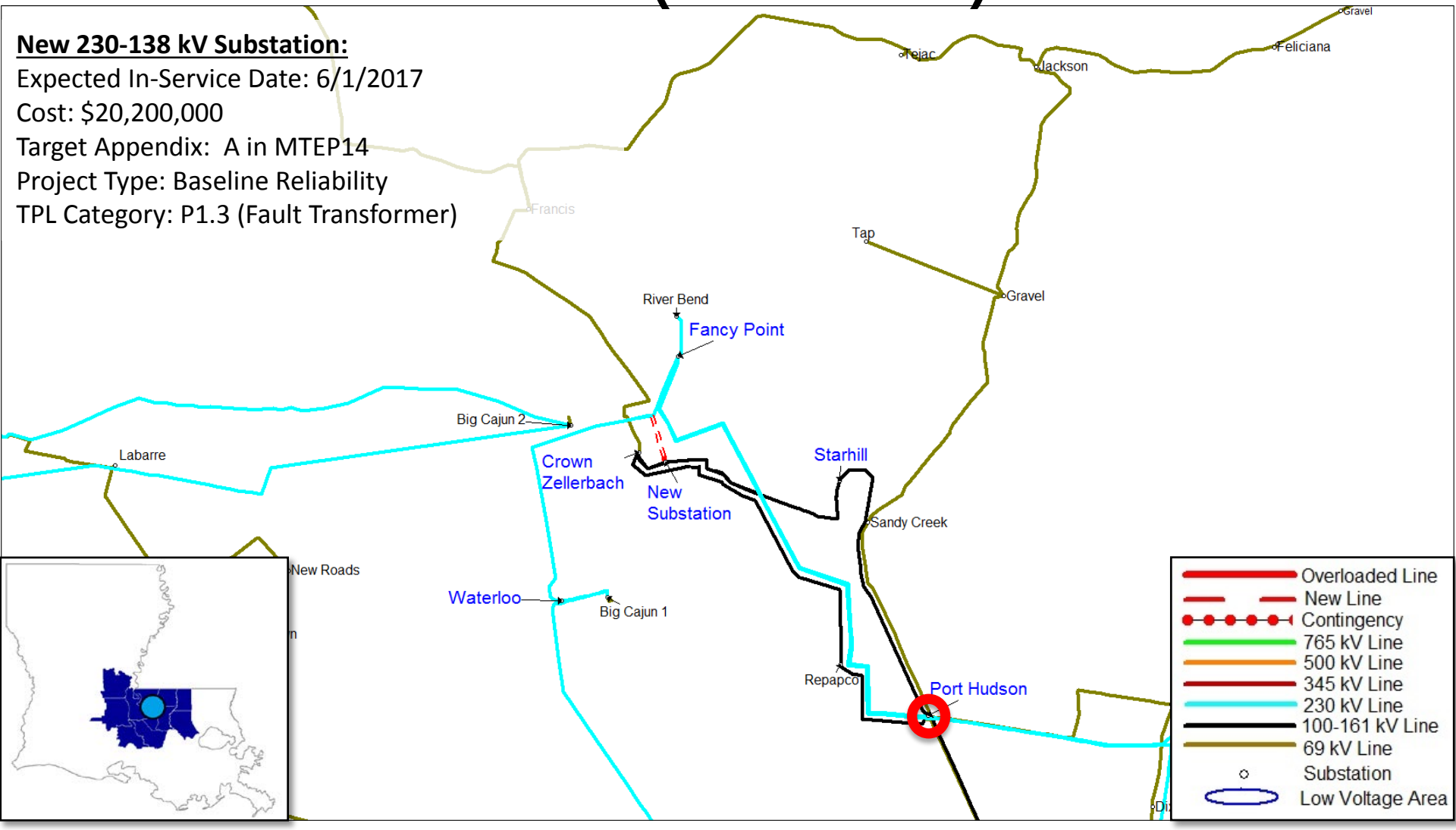
Crown Zellerbach Area
P4605 (14-EGL-017)

New 230-138 kV Substation:
Expected In-Service Date: 6/1/2017
Cost: $20,200,000
Target Appendix: A in MTEP14
Project Type: Baseline Reliability
TPL Category: P1.3 (Fault Transformer)



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Projects Driven by New Load Addition

Target Appendix	Prj ID	Project Name	Project Description	Expected ISD	Estimated Cost
A in MTEP14	4720	Michigan 230 kV substation: Construct new Michigan 230 kV substation and cut in to the Nelson to Verdine 230 kV line	Construct new Michigan 230 kV substation and cut-in to the existing Nelson to Verdine 230 kV line	6/1/2015	$14,700,000
	4768	Boxwood 230 kV Substation: Cut-in new substation on the Willow Glen to Brittany 230 kV line	Construct new Boxwood 230 kV Substation	12/1/2014	$10,943,000
	4769	Schriever: Construct new 230 kV substation	Construct new Schriever 230 kV Substation	12/1/2017	$9,391,000
	4783	Haute 115 kV Substation: Construct new substation and cut into existing Lutcher to Belle Point 115 kV line	Construct new Haute 115 kV Substation	6/1/2014	$2,553,000
	4784	Derrick 230 kV Substation: Construct new 230 kV substation and cut into Iberville to Chenago 230 kV line	Construct new Derrick 230 kV Substation	5/6/2014	$7,650,000
	4794	Midtown: Add 230 kV distribution transformers	Reconfigure Midtown 230kV Substation into a distribution substation	12/1/2014	$27,300,000

Projects Driven by Short Circuit Interrupting Capacity

Target Appendix	Prj ID	Project Name	Project Description	Expected ISD	Estimated Cost
A in MTEP14	4763	EGSL Underrated Breaker Project: Jaguar 69 kV 20940-CO	Upgrade breaker to increase short circuit interrupting capability	12/1/2016	$1,480,000
	4764	EGSL Underrated Breaker Project: Jaguar 69 kV 20905-CO			
	4765	EGSL Underrated Breaker Project: Blount 69 kV 14105-TC			
	4766	EGSL Underrated Breaker Project: Coly 230 kV 21825-C			
	4767	EGSL Underrated Breaker Project: Coly 230 kV 21830-C			

Projects Driven by Short Circuit Interrupting Capacity

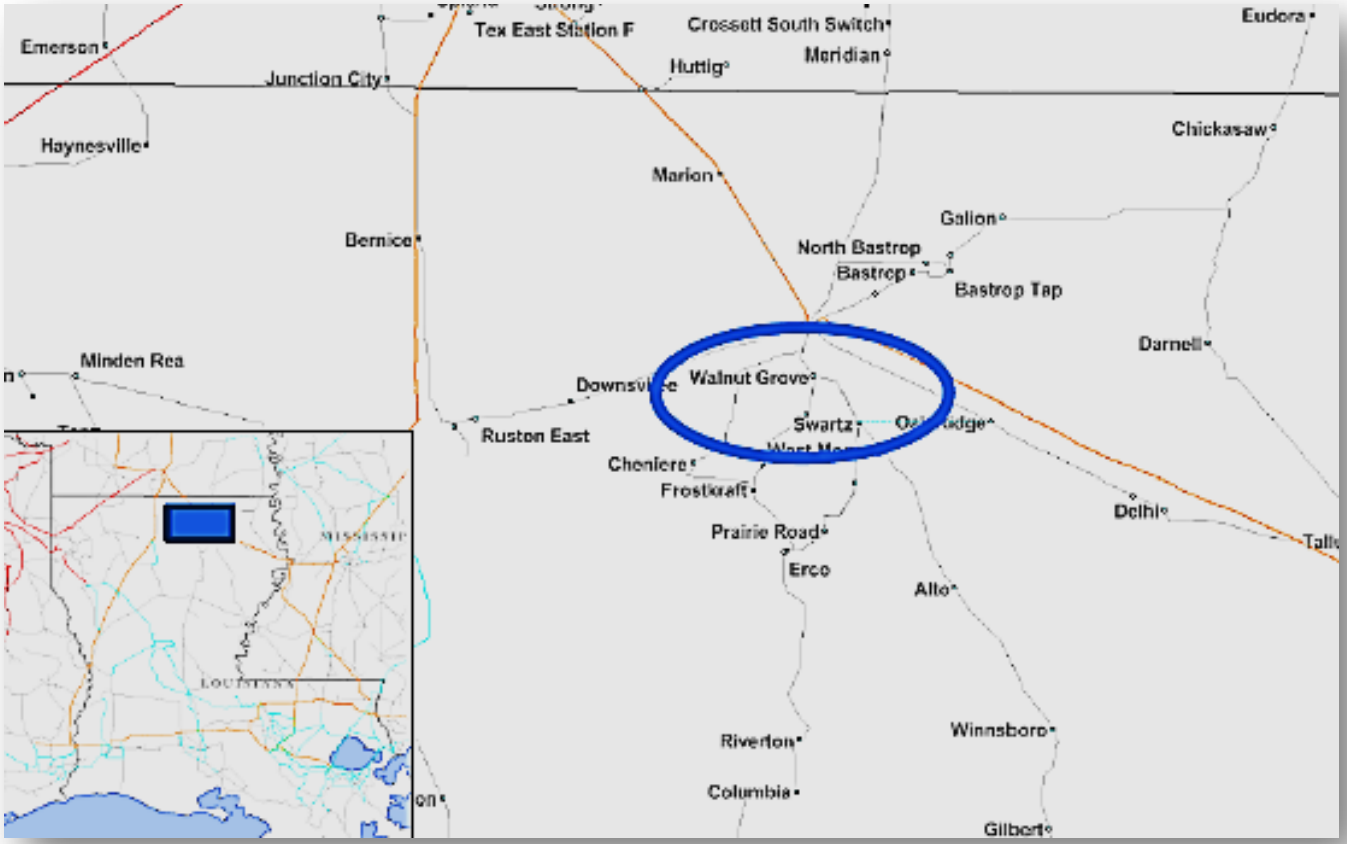
Target Appendix	Prj ID	Project Name	Project Description	Expected ISD	Estimated Cost
A in MTEP14	4770	ELL Underrated Breaker Project: Waterford 230 kV S1745-CO	Upgrade breaker to increase short circuit interrupting capability	12/1/2016	$1,082,000
	4771	ELL Underrated Breaker Project: Waterford 230 kV S1754-CO			
	4772	ELL Underrated Breaker Project: Ninemile 115 kV S6342-CO			
	4795	ENOI Underrated Breaker Project: Claiborne 115 kV N0143-ICBO	Upgrade breaker to increase short circuit interrupting capability	12/1/2014	$489,600
	4796	ENOI Underrated Breaker Project: Claiborne 115 kV N0123-ICBO			

Projects Driven by Protection System Modification

Target Appendix	Prj ID	Project Name	Project Description	Expected ISD	Estimated Cost
A in MTEP14	4761	EGSL SPOF Projects: Modify relaying at Willow Glen 500 kV	EGSL SPOF Projects: Modify relaying at Willow Glen 500 kV	6/1/2015	$450,700
	4762	EGSL SPOF Projects: Modify relaying at Fancy Point 500 kV	EGSL SPOF Projects: Modify relaying at Fancy Point 500 kV		
	4773	ELL SPOF Projects: Modify relaying at Ninemile 230 kV	ELL SPOF Projects: Modify relaying at Ninemile 230 kV	6/1/2015	$2,003,500
	4774	ELL SPOF Projects: Modify relaying at Southport 230 kV	ELL SPOF Projects: Modify relaying at Southport 230 kV		
	4775	ELL SPOF Projects: Modify relaying at Labarre 230 kV	ELL SPOF Projects: Modify relaying at Labarre 230 kV		
	4776	ELL SPOF Projects: Modify relaying at Harrahan 230 kV	ELL SPOF Projects: Modify relaying at Harrahan 230 kV		
	4777	ELL SPOF Projects: Modify relaying at Paris 230 kV	ELL SPOF Projects: Modify relaying at Paris 230 kV		
	4778	ENOI SPOF Projects: Modify relaying at Market Street 230 kV	ENOI SPOF Projects: Modify relaying at Market Street 230 kV		

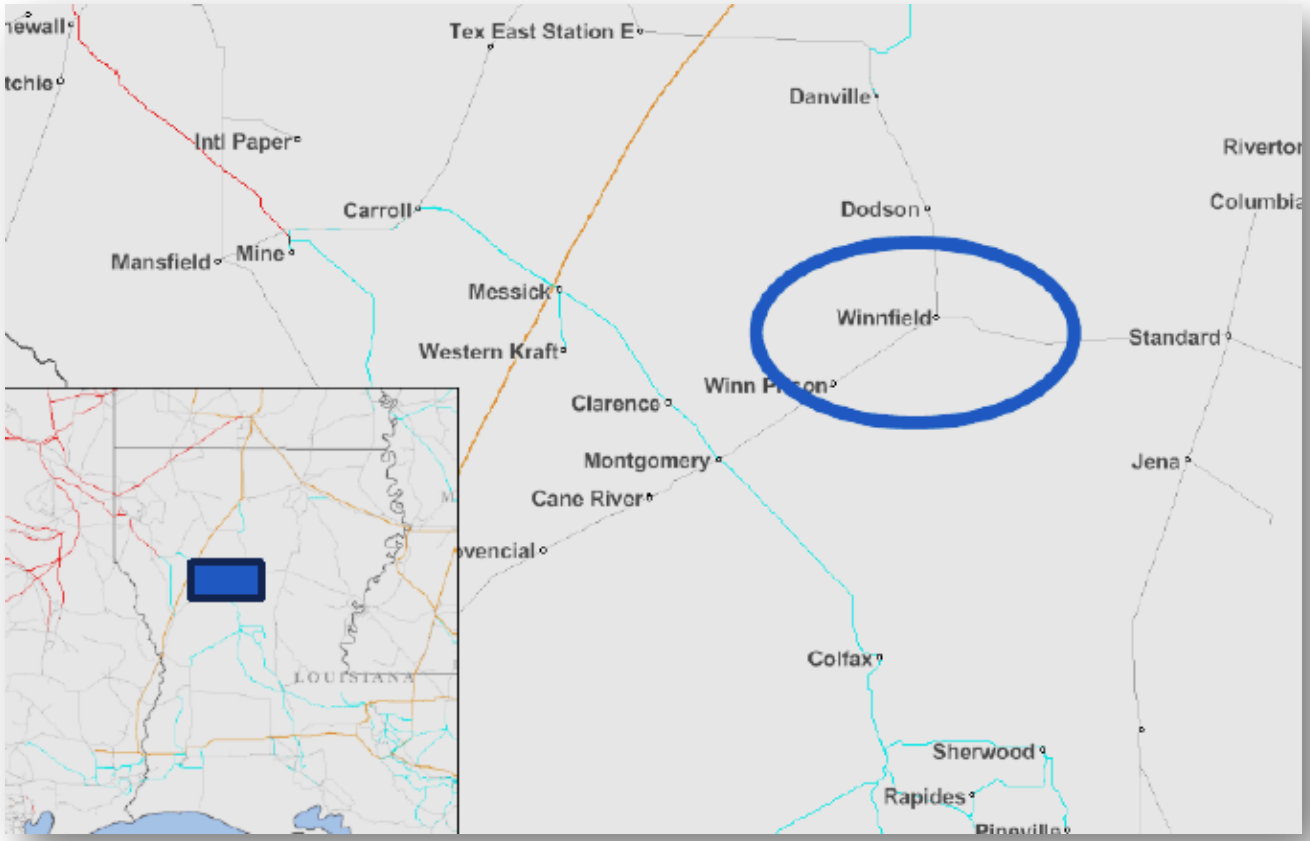
Zone 9 CIL Determination

- Limit 3,585 MW
  - Constraint: Walnut Grove to Swartz 115 kV line
  - Contingency: Perryville to Baxter Wilson 500 kV line



Zone 9 CEL Determination

- Initial limit 3,616 MW
  - Constraint: Winnfield 230/115 kV transformer
  - Contingency: Montgomery to Clarence 230 kV line



2014/2015 MISO Planning Resource Auction Results

LRZ	Z1 (MN,ND, Western WI)	Z2 (Eastern WI, Upper MI)	Z3 (IA)	Z4 (IL)	Z5 (MO)	Z6 (IN, KY)	Z7 (MI)	Z8 (AR)	Z9 (LA, MS, TX)	System
Demand Forecast	16,540	12,347	8,757	9,680	8,106	17,629	20,791	7,363	22,999	124,212
PRMR (based on CPF)	18,236	13,504	9,628	10,616	8,884	19,404	22,998	8,043	25,224	136,537
Local Clearing Rqt (LCR)	15,070	11,739	8,971	8,879	5,002	15,457	21,293	8,417	24,080	N/A
Effective PRMR	18,236	13,504	9,628	10,616	8,884	19,404	22,998	8,417	25,224	136,912
Total Offer Submitted	7,045	2,879	9,520	11,370	387	17,985	15,190	9,406	25,966	99,747
Total FRAP applied	12,620	12,352	391	874	7,722	1,846	8,449	397	2,372	47,022
Offer Cleared + FRAP	18,522	14,358	9,787	9,316	8,109	19,551	22,627	8,582	26,059	136,912
Import Limit	4,347	3,083	1,591	3,025	5,273	4,834	3,884	1,602	3,585	N/A
Export Limit	286	1,924	1,875	1,961	1,350	2,246	4,517	3,080	3,616	N/A
Import/(Export)	(286)	(854)	(158)	1,299	774	(148)	371.7	(165)*	(835)*	N/A
ACP ($/MW-Day)	3.29	16.75	16.75	16.75	16.75	16.75	16.75	16.44	16.44	N/A

* Zones 8 & 9 were limited to 1,000 MW aggregate imports or exports

Participation by Resource Type (System-wide)

Planning Resource Type	Capacity (UCAP)	Unused Capacity	Offers	Cleared	Fixed Resource Plans	Commit	% Commit	ZRC Balance
Generation	138,668	3,480	90,645	82,162	42,394	124,556	91.0%	10,632
Behind the Meter Generation	4,071	59	1,693	1,602	2,141	3,743	2.7%	270
Demand Response	5,750	3	4,298	4,008	1,449	5,457	4.0%	290
External Resources	4,238	73	3,111	2,117	1,038	3,156	2.3%	1,009
Energy Efficiency	0	0	0	0	0	0	0%	0
Total	152,727	3,615	99,747	89,890	47,022	136,912	100%	12,201
%UCAP	100%	2%	65%	59%	31%	89.6%	89.6%	8%