

An Overview of the Midwest ISO Market Design

***Michael Robinson
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The Role of RTOs

- Monitor flow of power over the grid
- Schedule transmission service
- Perform transmission security analysis for the Reliability Area footprint
- Manage power congestion through LMPs
- Approve transmission & coordinate generation maintenance outages
- Perform long term planning & analysis for region
- Operate Real-Time & Day-Ahead Markets

Why markets?

Why a Midwest ISO administered market?

- *Create a framework for robust, transparent and competitive electric markets.*
 - *Markets work better when there are many buyers and sellers*
 - *Competition yields lower prices*
 - *Sellers will build if there's an opportunity to earn a return commensurate with the risks.*
- *Competitive markets are efficient!*
 - *Maximizing consumer welfare*
 - *'Correct' allocation of scarce resources*
 - *Production at lowest cost*

Section 1: The Basics

The purpose of this section is to introduce and reinforce basic concepts that are fundamental to electricity market design.

Physics

- As a *physical commodity*, electricity has unique characteristics encapsulated in:
 - 1) Ohm's Law:
 - *The current (i.e. amps) through a conductor, under constant conditions, is proportional to the difference of potential (i.e. the voltage) across the conductor...AND*
 - 2) Kirchoff's 2nd Law:
 - *In any closed circuit, the algebraic sum of the products of the current and the resistance of each part of the circuit is equal to the resultant electro magnetic force in the circuit.*
- Why are these important?
 - Because you can't fool Mother Nature!
 - Power flows according to the laws of physics and not by commercial desire, government decree, or market design!

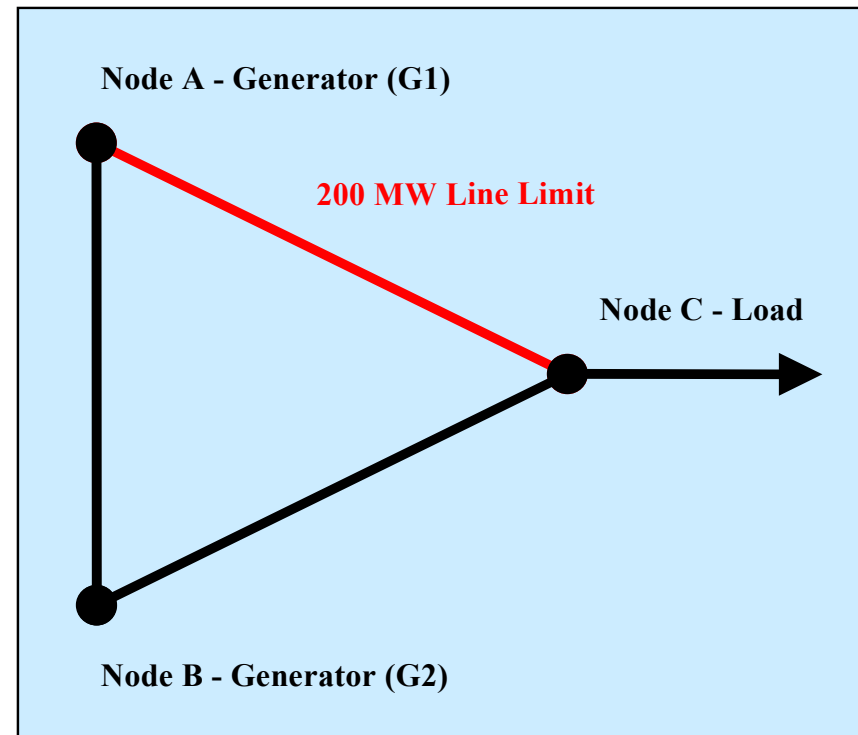
Economics

- As an *economic commodity*, electricity has several important characteristics:
 - 1) Difficulty/impossibility of storing electricity.
 - Within tight bounds, supply and demand must always be equal.
 - 2) Network production
 - Can't establish/define property rights on an interconnected grid.
 - Can't separate the commodity (electricity) from delivery (dispatch).
 - 3) Network externalities
 - Decisions about reliability cannot be totally separated from "energy."
- Why are these important?
 - Because in the long run you can't fool the market.
 - Failure to recognize/incorporate these characteristics into the market design creates inefficiencies and ultimately to collapse.

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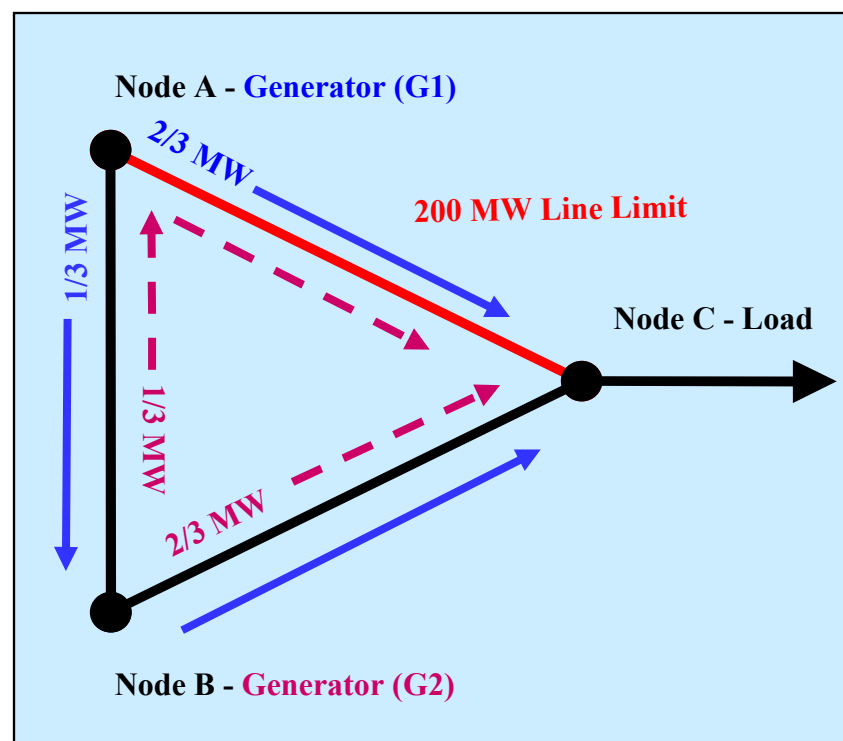
The Basics – A Simple Model

- Start with a simple network model:
 - 3 interconnected nodes.
 - 3 transmission lines with equal impedance and of equal length.
 - 1 thermally constrained transmission line (line AC)
 - Line AC is constrained to no more than 200 MW.
 - Lines AB and BC have unlimited MW capacity.
 - 2 generators (G1 and G2)
 - 1 load



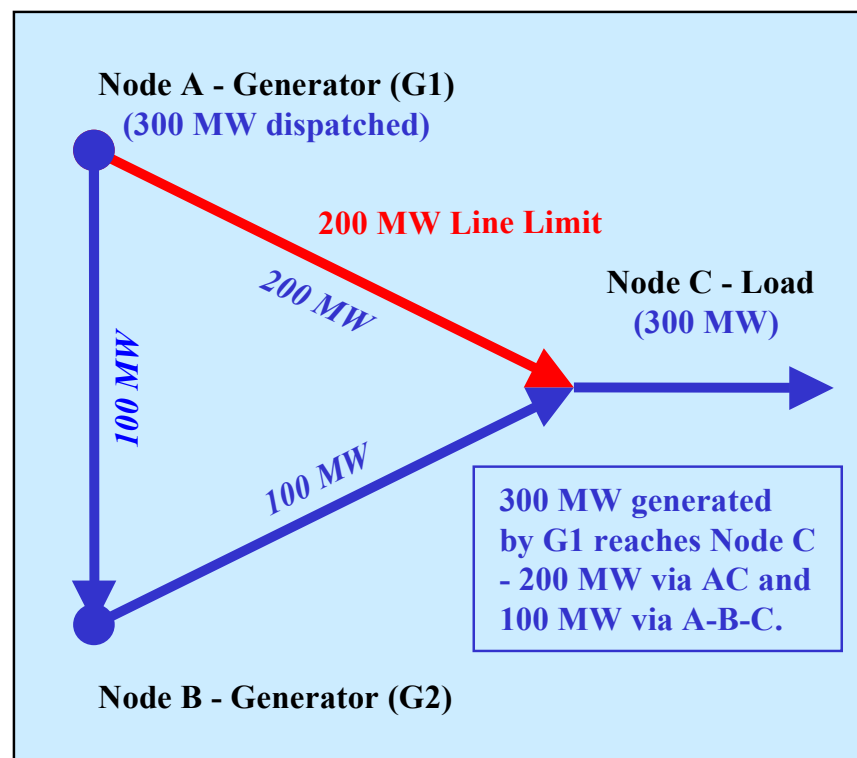
The Basics – Physics

- Based on physics:
 - If G1 injects 1 MW (at Node A) - $2/3$ MW flows along AC and $1/3$ MW flows along AB and then BC.
 - Likewise, if G2 injects 1 MW (at Node B) – $2/3$ MW flows along BC and $1/3$ MW flows along BA and then AC.



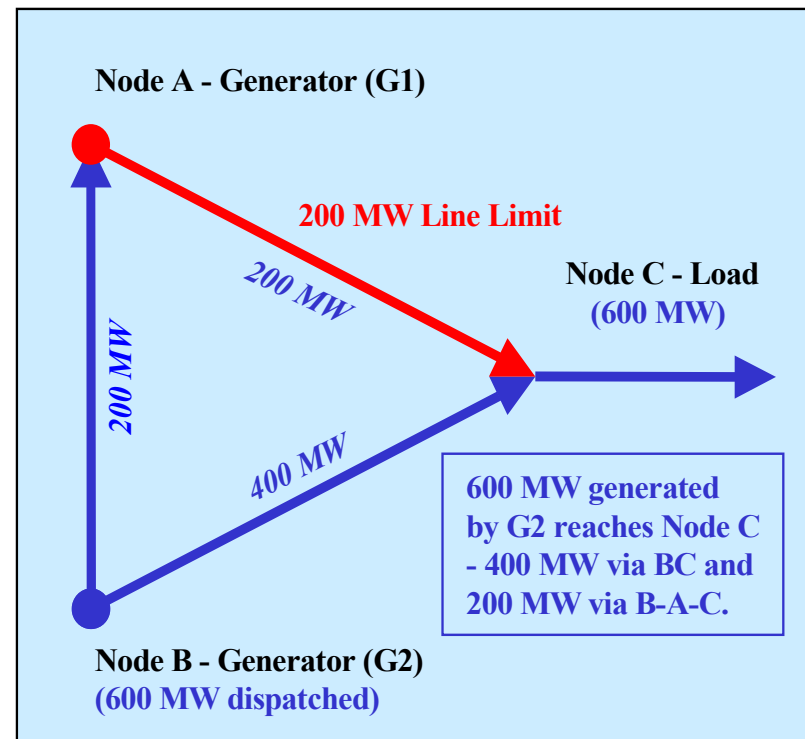
The Basics – Defining Capacity

- *IF*, load at Node C is 300 MW
 - Then it is possible for G1 to meet all the load
 - Depends on offer curves.
 - But...if G1 does produce 300MW then G2 cannot produce anything.
- *IF*, G1 produces 300MW then the Total Transfer Capability (TTC) is 300MW
 - Neither G1 or G2 can produce more output without violating line limits.



The Basics – Defining Capacity (2)

- *IF*, load at Node C is 600 MW
 - Then it is possible for G2 to meet all the load
 - Assuming G2 does produce 600MW then G1 cannot produce anything.
- *IF*, G2 produces 600MW then the TTC is 600MW
 - Neither G1 or G2 can produce more output.



Aligning the Physics and the Economics

- Impossible to accurately define – *for dispatch purposes* – the actual capacity of a transmission network.
 - Why is this so important?
 - Since electricity cannot be stored, *real time* supply and *real time* demand must always be in equilibrium – there is no buffer (no “line pack” to use a term from the gas market).
 - The dispatch process – if it is to be non-discriminatory and efficient – cannot be based on rights to the capacity of the transmission system.
 - To see why, consider the task of the air traffic controller (I.e the “dispatcher” for an airport)
 - Their job is to coordinate the take-off and landing of airplanes.
 - They accomplish this by applying “property” rights based on landing capacity, i.e. decisions on who can land/take-off, how often, etc are based on these rights.
 - BUT...what if the “capacity” (e.g. the amount of rights that had been created) wasn't constant...

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Section 1 – Concluding Remarks

- Day 1 operations were based on:
 - Defining transmission capacity for purposes of daily operations/commercial transactions (as opposed to transmission planning). Deviations between actual and expected are handled through the “Transmission Loading Relief” (TLR) process – which is a physical and not financial rationing mechanism, i.e a transaction is “cut” or not allowed to take place.
 - Dispatch is not as efficient as it could be.
 - Redispatch takes place largely outside of the “market”.
 - Creates uncertainty about price. Increases financial risk.
 - Artificial distinction maintained between reliability and energy.

Section 2: Real Time

Real time refers to the activities focused on coordinating instantaneous power flows. The purpose of this section is to explain how this is accomplished.

Day 1 Midwest Market

- **Bilateral transactions facilitated by “physical” transmission service provided under regional OATT**
- **MISO’s primary responsibilities related to the market included:**
 - **Acceptance and analysis of requests to reserve transmission capacity for future scheduling of transactions**
 - **Acceptance of schedules for approved reservations**
 - **Monitoring transmission usage**
 - **Providing reliability coordination**
 - **Invoicing participants monthly for use of transmission lines as well as other associated services**

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Day 2 : Real Time 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.

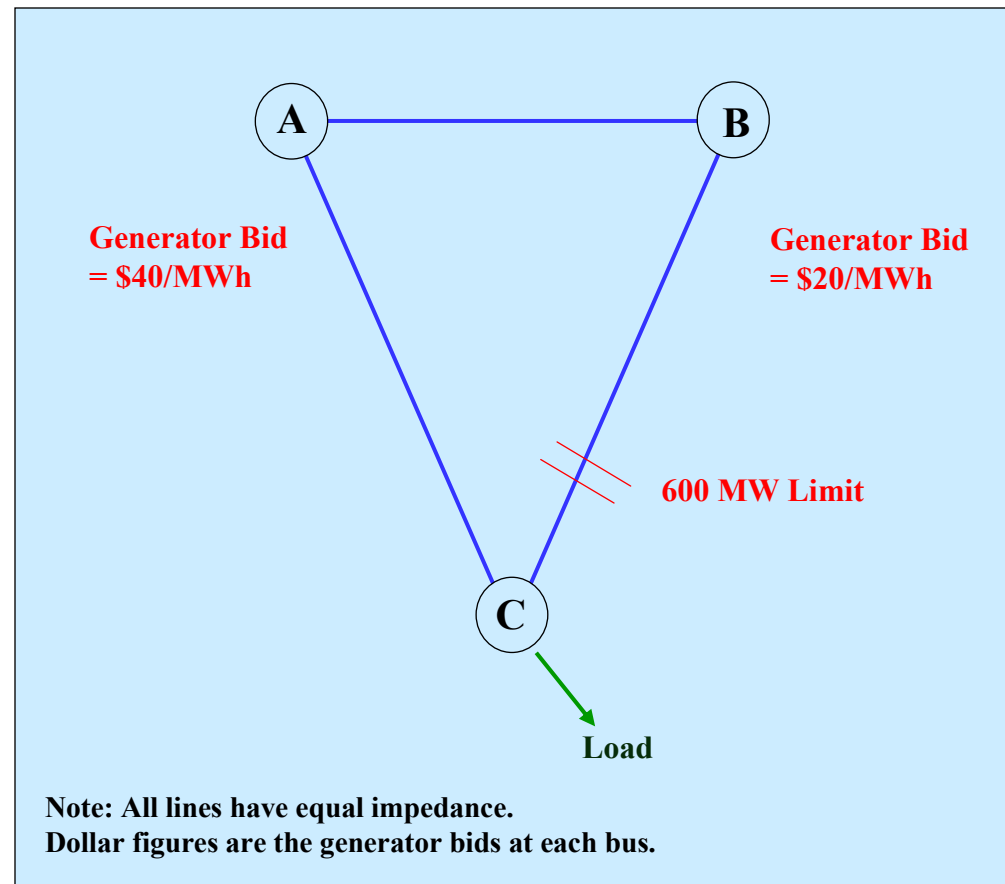
What is LMP?

- 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!***

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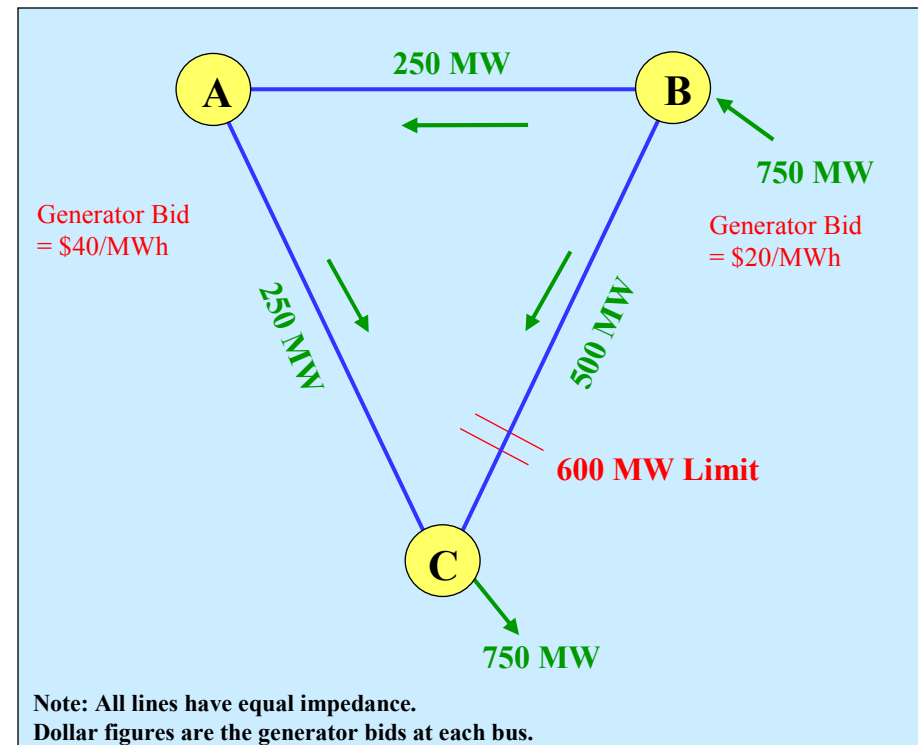
Example of Dispatch and Price Calculation

- 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.



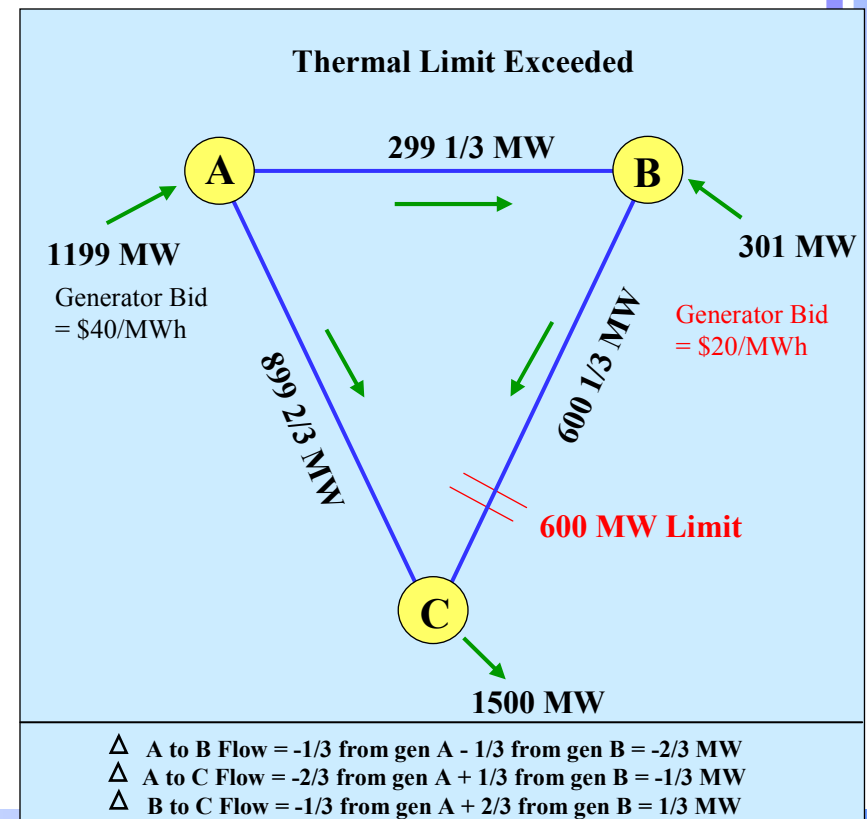
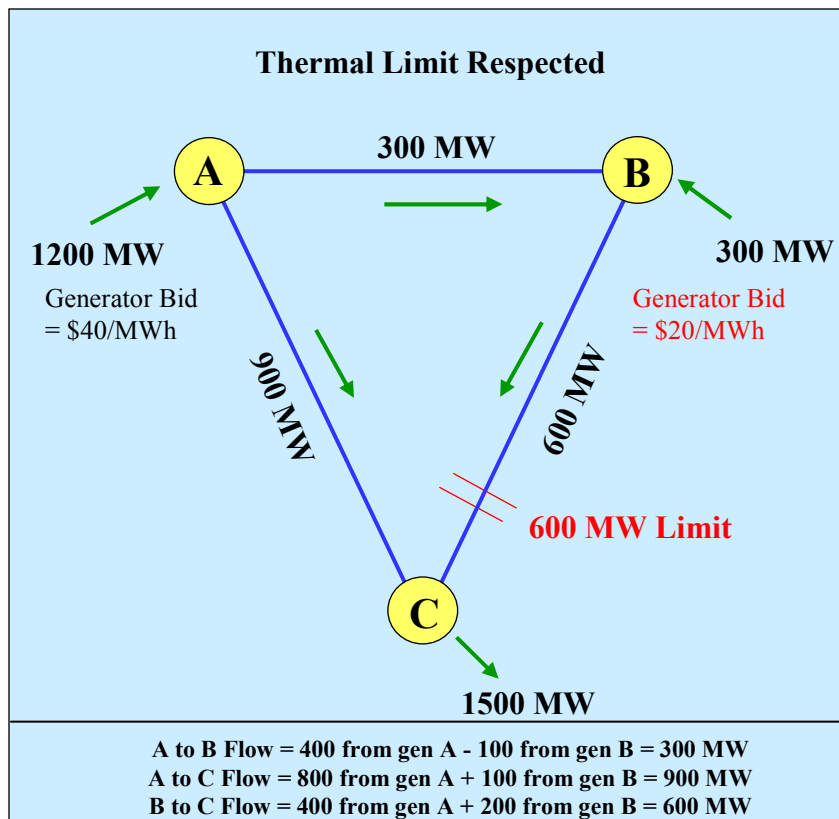
Unconstrained Least Offer Cost Dispatch

- 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.



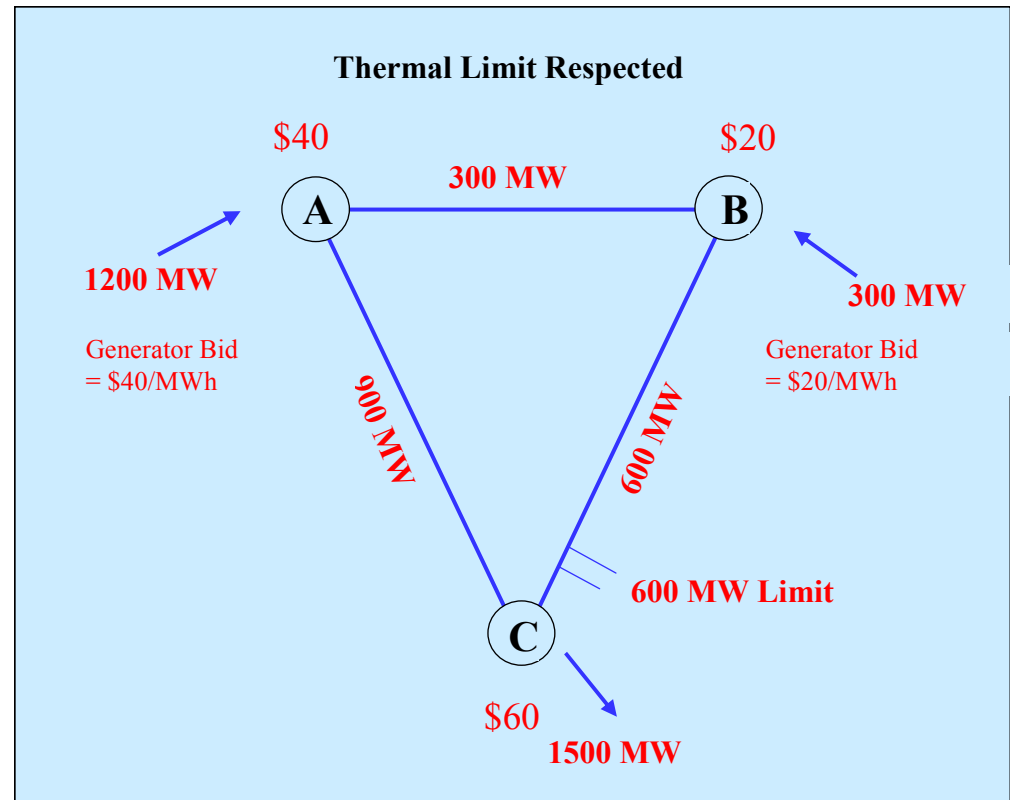
Note: All lines have equal impedance. Dollar figures are the generator offers at each bus.

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.

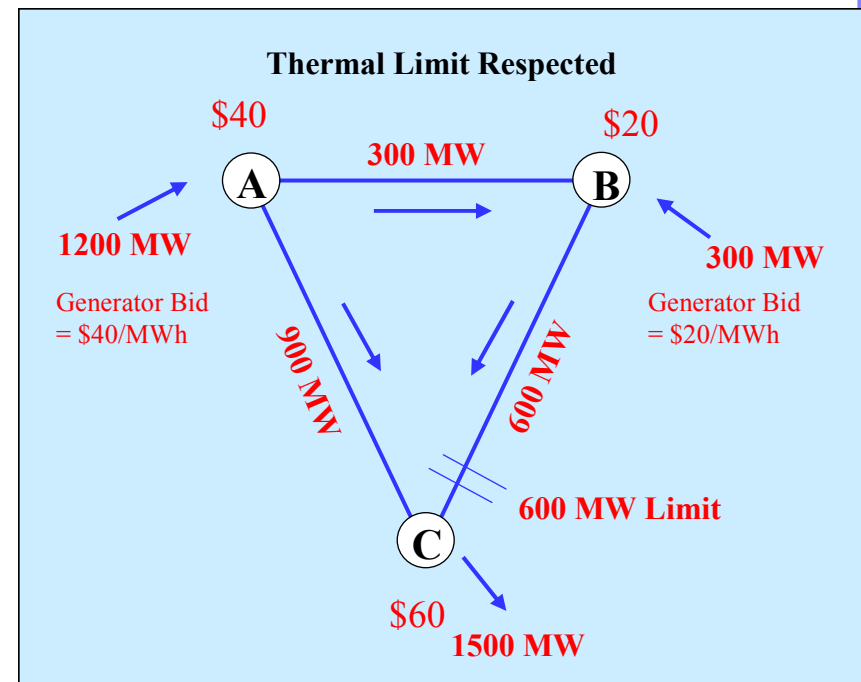
Price Derivation

- 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.



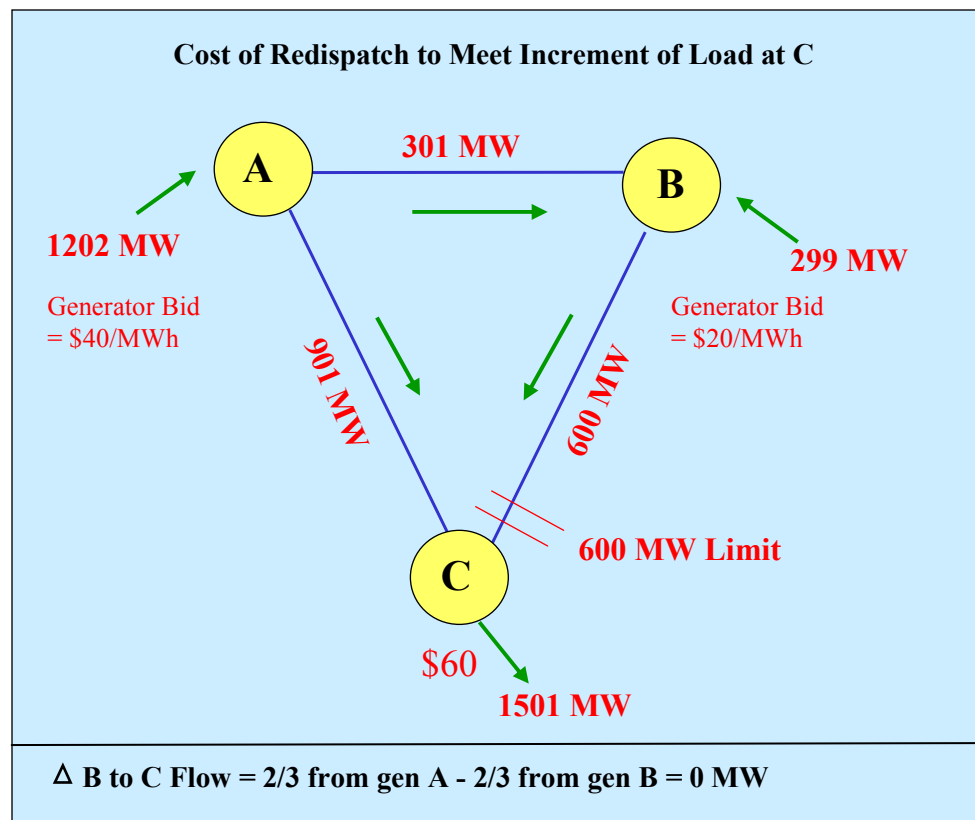
Price Derivation at Locations A & B

- 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 ($2\text{MW} * \$40 - 1\text{MW} * \$20 = \$60$).



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.
 - **$LMP_w - LMP_i = \text{Congestion Charge}$**

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 (G_a) will get paid - *from the pool*:
 - $\$40 * 1200 \text{ MW} = \$48,000$
 - The generator at B (G_b) will get paid - *from the pool*:
 - $\$20 * 300 \text{ MW} = \$6,000$
 - 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, etc)

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 \text{ MW} = \6000
 - Ga: $\$40 * 800 \text{ MW} = \$32,000$
 - Total = \$38,000
 - Payments from load would be:
 - Load at C: $\$60 * 1100 \text{ MW} = \$66,000$
 - Schedule C-A: $\$20 * 400 \text{ MW} = \$8,000$
 - 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.

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Real-Time Centralized Dispatch

- MISO uses the Security Constrained Economic Dispatch (SCED) program every 5 minutes of each operating hour
- MISO sends control areas Net Scheduled Interchange (NSI) and basepoints for generators
 - NSI and resource basepoints sent every 5 minutes
 - Dynamic Schedules sent every 5 minutes
 - Ramped Control Area NSI sent every 4 seconds
 - Ramped Dynamic Schedule values sent every 4 seconds
- Control Areas are responsible for regulation between dispatch interval and for operating reserves (this is no longer true effective 6 January 2009)
- MISO calculates ex-post Real-Time LMPs based on actual system activity

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Section 3:

Other Market Design Elements

The Real Time market operator and the market participants want some certainty that enough resources are available every five minutes to meet the load demands, or to keep the lights on.

Midwest ISO Energy Markets

- The critical design elements included in these Markets are:
 - **Real-Time Centralized Dispatch**
 - **Integrated Energy and Congestion Management Day-Ahead Market**
 - **Locational Marginal Pricing (LMP)**
 - **Financial Transmission Rights**
 - **Reliability Assessment Commitment (RAC)**
 - **Self-Schedules and Bilateral Schedules**
 - **Use Limited and Demand Response Resources**
 - **Load Aggregation and Trading Hubs**
 - **Market Timeline**
 - **Market Power Mitigation**
 - **Security Constrained Unit Commitment (SCUC)**
 - **Resource Adequacy**
 - **Pre-OATT Contracts (grand fathered agreements)**
 - **Ancillary Service Procurement**
 - **Control Area Activities**
 - **Market Settlements**

Day-Ahead Market

- What it is
- Why it exists
- Seller options
- Buyer options
- Virtual participants
- Timing requirements
- MISO role
- Settlements Supply Offers and Demand Bids are due at 1100 EST on the day prior to the operating day

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Day-Ahead Market

What it is:

- A financial day-ahead market, settled hourly, where market participants can buy or sell energy, schedule transactions or hedge congestion costs at financially binding locational marginal prices (LMPs).
- While the day-ahead market is purely financial, the Midwest ISO clears this market using a network topology that ensures that the day ahead solution is physically feasible (I.e., day-ahead scheduled injections and leakages could actually flow across the Midwest ISO grid).

Day-Ahead Market

Why it exists:

- Allows market participants to hedge congestion costs and schedule transmission usage
- Allows market participants that are long or short to alter their positions
- Shifting market activities from real-time to day-ahead improves grid reliability

Day-Ahead Market

Seller options:

- Resource types
 - Capacity resources (must offer)
 - Other resources
 - Demand response resources
- Self schedule (price taker)
- Bilateral schedule
 - Financial
 - Physical (imports)
- Supply offers
 - One-part or three-part
 - Physical parameters (start time, ramp rate, ...)
 - Reserve offers
 - Offer caps & floors

Day-Ahead Market

Buyer options:

- No mandatory requirement on % of load that must be bid
- Demand bids
 - Self schedule
 - Price responsive demand bids
- Load aggregation pricing points: choice

Day-Ahead Market

Virtual participants:

- Virtual transactions allowed in the day-ahead market
 - Day-ahead transactions that have no physical backing and will never actually flow in real-time, by definition
- Virtual supply offers and demand bids allowed
- Individual market participant benefits
 - Hedge physical supply availability
 - Hedge load uncertainty
- Market benefits
 - Enhanced liquidity
 - Improved day-ahead/real-time price conversion

Day-Ahead Market

Midwest ISO role:

- Solve the Day-Ahead market simultaneously for all hours of the next operating day to:
 - clear Supply Offers and Demand Bids for each Hour of the Operating Day to yield Day-Ahead Schedules
 - efficiently allocate transmission capacity to Day-Ahead Schedules by resolving transmission congestion
 - commit unscheduled Resources at least-cost to meet the Energy requirements throughout the Operating Day.

Day-Ahead Market

Timing & process requirements:

- Market closes at 11:00 am EST (offers/bids/schedules due)
- Post results by 5:00 pm EST
- Market monitoring
- Perform security constrained economic dispatch (minimize as-bid overall costs of energy procurement)
- Represent network topology, line limits, AFC constraints and resource outages as close as possible to real-time conditions
- Represent loop flow assumptions as accurate as possible
- Handle shortage and surplus conditions

Day-Ahead Market

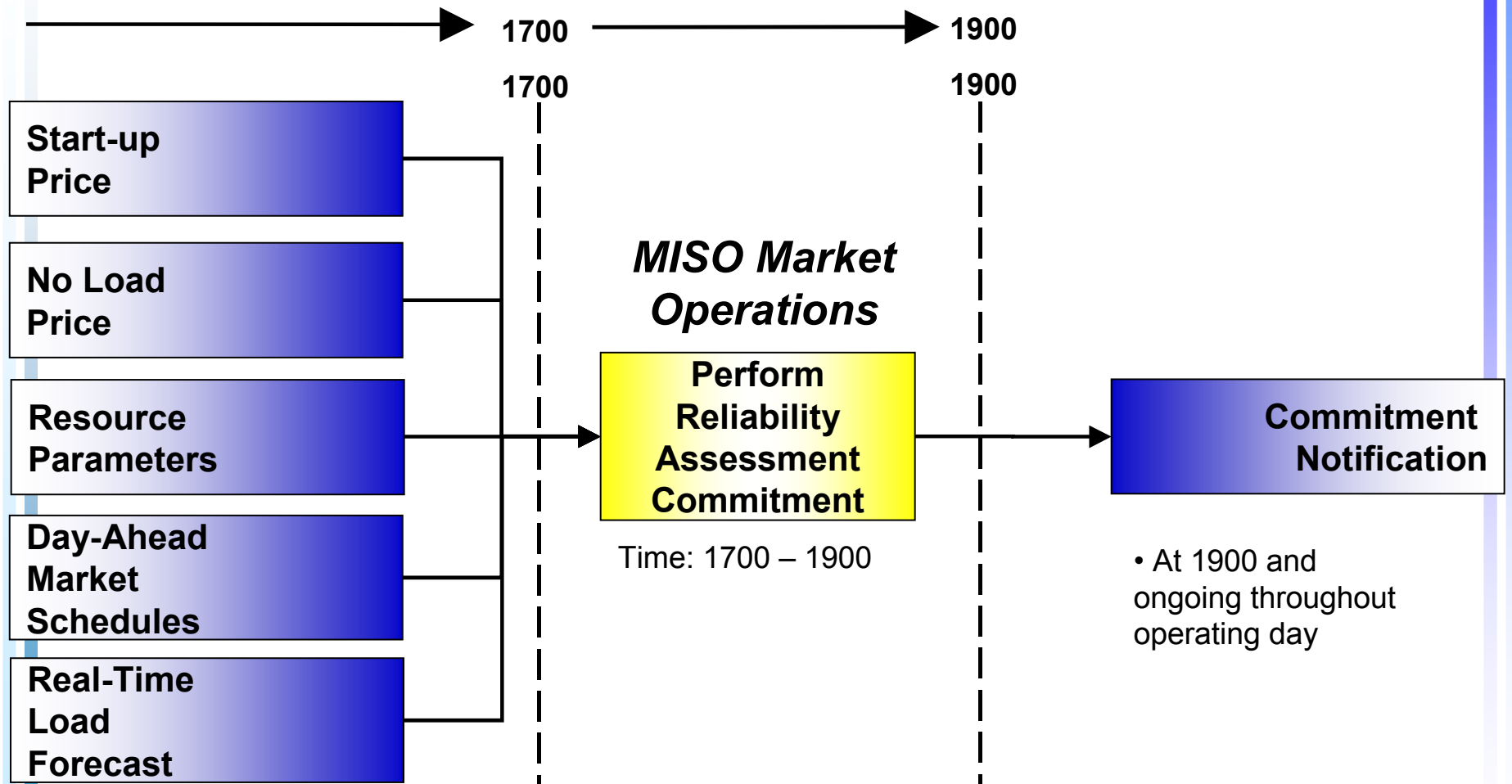
Settlements:

- LMPs calculated at each pricing node
- Day-Ahead credits applied to
 - Cleared supply offers
 - MISO-committed units
 - FTR rights holders
- Day-Ahead charges applied to
 - Cleared demand bids
 - Bilateral schedules (congestion and loss charges)
 - Unrecovered commitment costs (RSG)
 - FTR rights holders (negative congestion)

Reliability Assessment Commitment (RAC) process

- RAC process ensures that sufficient resources are available and online to meet the forecasted load for each hour of the next operating day
- Selected resources are guaranteed recovery of start up and no load offers

RAC Inputs and Outputs



Financial Transmission Rights

- Midwest ISO's congestion management system includes Financial Transmission Rights (FTRs)
 - Market Participants may acquire FTRs to hedge congestion costs
- FTRs are financial instruments
 - Market Participants need not hold FTRs to schedule transactions
 - An FTR Holder is not required to schedule transactions by virtue of holding FTRs
- Only Market Participants can hold FTRs
- An annual allocation is performed to allocate FTRs to existing transmission customers using a simultaneous feasibility algorithm

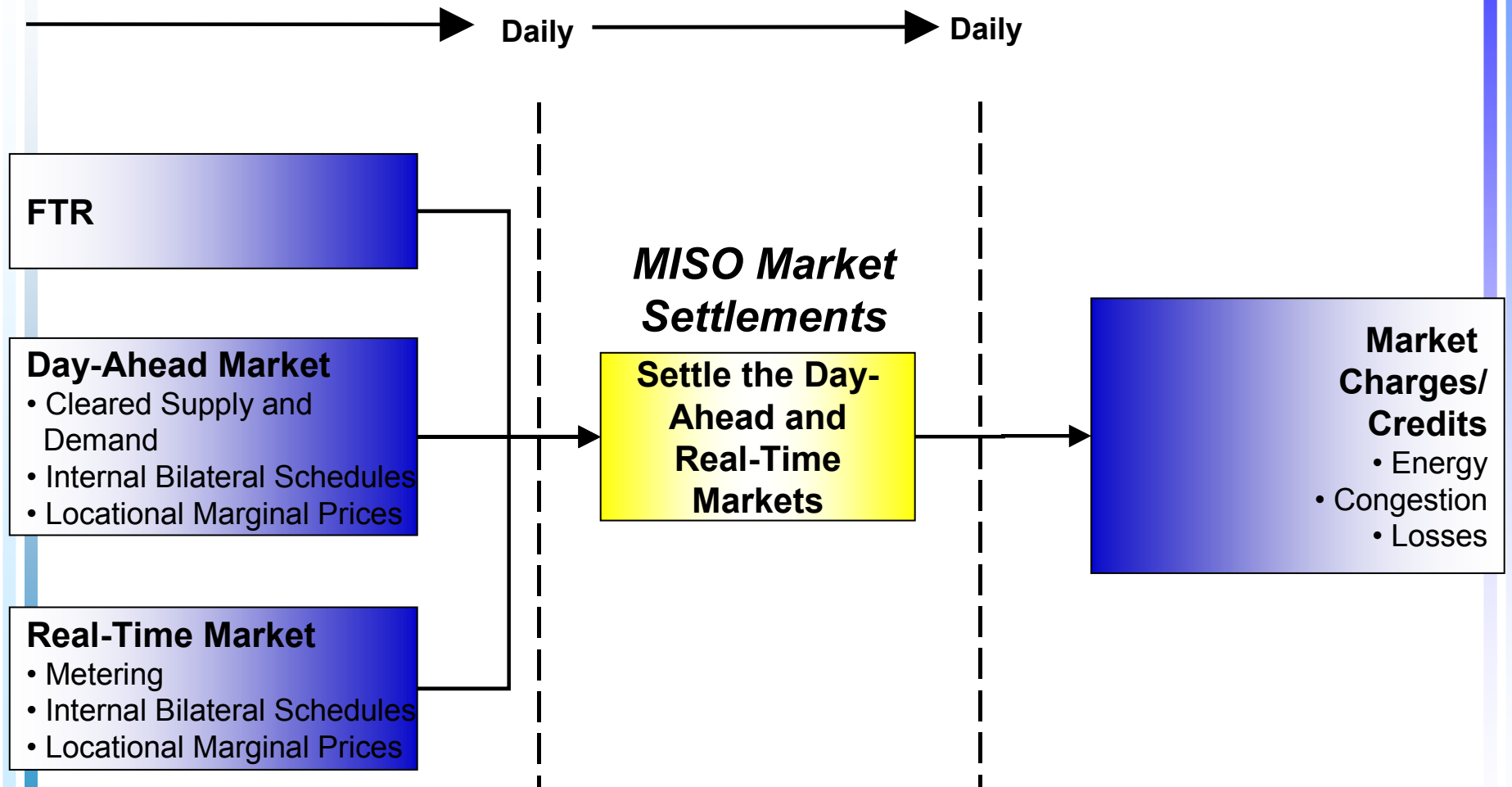
Acquiring FTRs

- FTRs are awarded annually in a manner that affords transmission customers under existing transmission contracts the same level and quality of transmission service, to the extent possible given the requirement of simultaneous feasibility
- The Midwest ISO conducts voluntary Annual and Monthly FTR Auctions
 - Market Participants may offer to sell allocated FTRs
 - The Midwest ISO will sell any residual monthly FTRs
- FTRs are awarded for new transmission service, to the extent feasible
- The Midwest ISO issues FTRs to all Market Participants that fund Network Upgrades

Settlements

- Settlements is the process of calculating the amount of money owed or to be charged to each Market Participant based upon their hourly/daily activities in the marketplace
- The MISO's Settlement System is revenue neutral
- Settlement statements include results for the Day Ahead and Real Time Energy Markets and for FTRs

Settlement Inputs and Outputs



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Market Monitoring and Mitigation

- **The Market Monitoring Plan is intended to provide for the independent impartial and effective monitoring and reporting on the Transmission Providers' Energy Markets as a whole. The plan's goal is to protect and foster competition while minimizing interference with open and competitive markets.**
- **The Market Mitigation Measures are intended to provide the means for the Transmission Provider to mitigate the market effects of any conduct that would distort competitive outcomes in the Energy Markets administered by the Transmission Provider.**

“Day 2” LMP Market Overview

- **The Midwest ISO 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**

Section 4: Summary

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Day 3: Objectives of Ancillary Services Market Design

Energy and operating reserve (OR) markets need to be designed properly, to provide the proper incentives for:

- Generators that are on-line to follow dispatch signals.
- Generators that are not on-line, but can make themselves available, to make themselves available during situations when the system is under significant stress.
- Loads would also have the proper incentives to reduce consumption at such times.
- Economically efficient amounts of generating or demand response capability to be built.

Incentives to Follow Dispatch Signals

Frequently, a trade-off exists between providing OR and providing energy.

- Resources that are providing OR with a given amount of capacity cannot normally provide energy using that capacity as well.
- Consequently, these resources forgo any margins above the variable cost of operation that they would earn from providing energy.

Resources must be appropriately compensated for this foregone opportunity.

- The payments they receive should encourage resources whose cost of providing OR is less than the market-clearing price of OR to provide as much OR as possible.
- But they should also encourage resources whose cost of providing energy is less than the market-clearing price of energy to provide as much energy as possible.

Incentives to Make Capacity Available

Failure to provide the appropriate incentives for resources that are off-line to make themselves available may result in insufficient response to shortage conditions.

- When there are shortages of OR, providing additional energy may further reduce the amount of OR that can be provided.
- In such cases, energy prices should appropriately reflect the value of the foregone OR.
- If the energy market is not priced in this way, the incentives for resources to make themselves available during such conditions will be less than the value that consumers place upon having those generators available.

Similarly, it is also important to provide the appropriate incentives for loads to reduce consumption.

Incentives to Develop Capacity

If energy and OR are appropriately priced, and providers of those services are paid those prices, incentives for development of the economically efficient amount of capacity will follow.

- The economically efficient amount of capacity is defined as the quantity of capacity at which the marginal cost of building additional capacity is equal to the marginal benefit of developing that capacity.
- If the price that a developer is paid for providing a service reflects the value of that service, the marginal revenue it receives as a result of developing that capacity will be equal to the marginal benefit of developing that capacity.

Of course, this does not preclude procedures that would lead to the development of additional capacity, through the introduction of other revenue sources, such as installed capacity payments for meeting ERO requirements.

Guidelines Permitting Objectives to Be Realized

Energy and operating reserves (OR) markets can achieve these three objectives if they follow these guidelines:

- Market-clearing prices in the real-time market for energy and OR must reflect the value calculated by the ISO of incremental energy and OR at each location and point in time.
- Providers of each of these services in real-time must be paid the market-clearing price of that service for the real-time market.
- The impact on prices of failure to meet energy or OR objectives must reflect the value of the foregone energy or OR.

Benefits for participants

- Reduced barriers to trade
 - Elimination of pancaked transmission rates
 - Uniform access -- one stop shopping for transmission service and interconnection
 - TLR replaced with market-based redispatch
- Coordinated markets
 - Liquidity/transparency
 - Expanded choices
 - Self-scheduled generation or load
 - Bilateral transactions
 - Spot purchases or sales
 - Forward hedging
 - Virtual transactions

Questions/comments?

Contact:

Michael Robinson

mrobinson@midwestiso.org

317.249.5741

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