U.S. Electricity Markets: Challenges and Opportunities for Battery Energy Storage Systems

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Energy Storage Seminar – State of the art of energy storage and insertion of intermittent renewable resources

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In this talk I will…

- Show how BES need access to all revenue streams
  - Revenues from electricity price arbitrage are not enough
    - Not in the past, not today, unsure for the future
  - Revenues from hybrid systems (with solar for example) are also unlikely to cover costs

- Discuss how **Battery Energy Storage** (**BES**) systems can recover their costs in U.S. wholesale electricity markets
  - FERC rule of February 15 2018
  - Implications for storage given U.S. markets design
  - Open questions

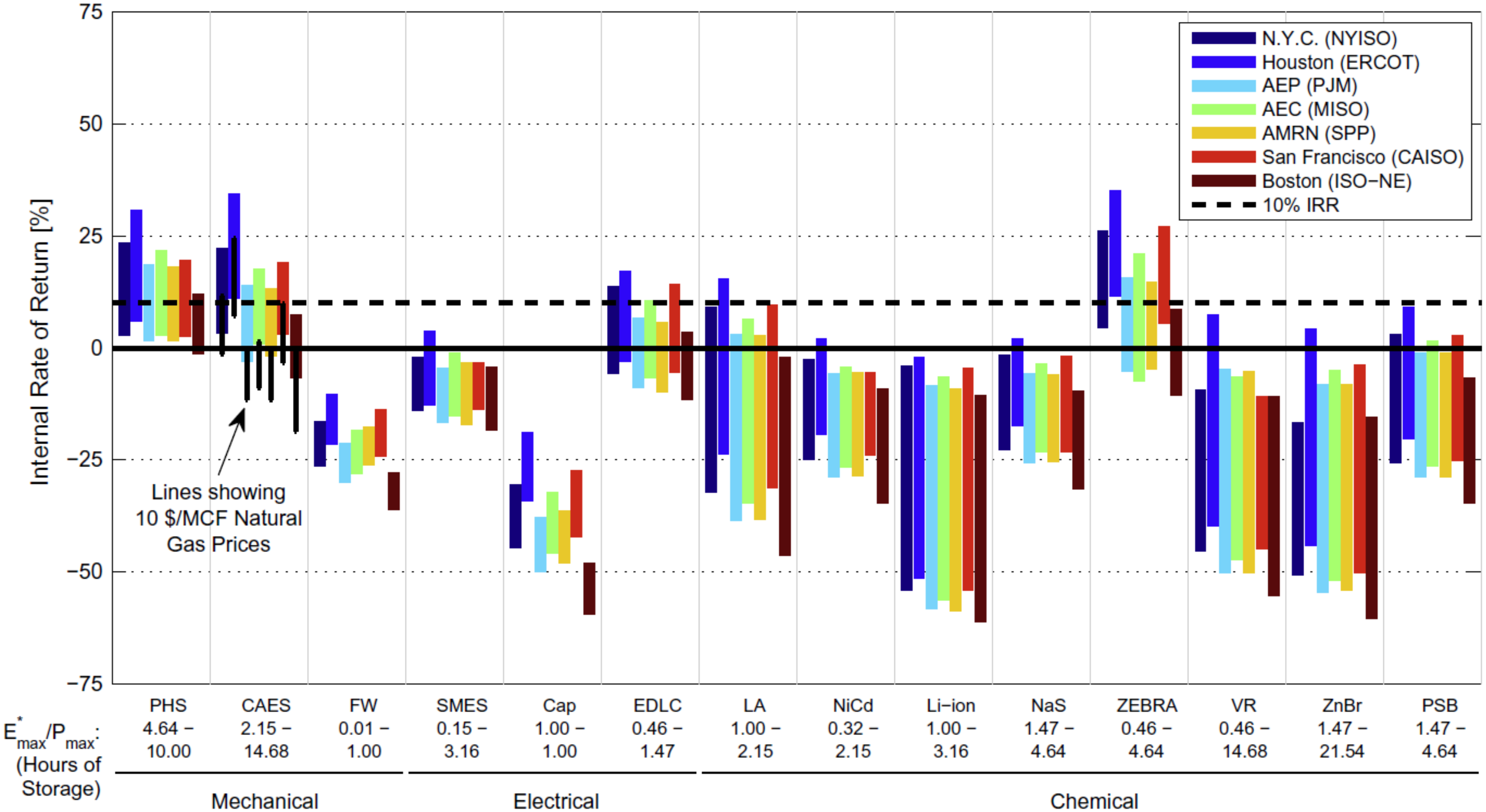
LCOE of BES still high

For all applications and all commercial technologies

- Peaker replacement (~285 - 580 $/MWh – 400 - 800$/kW/yr)
- Frequency regulation (~159 - 233 $/MWh)
- Transmission system (~270 - 560 $/MWh)
- Distribution
  - Substation (~345 - 657 $/MWh)
  - Feeder (~515 - 1000 $/MWh)

Hard to recover these costs through price arbitrage in energy markets

Profitability of price arbitrage for 17 ESS in 7 U.S. electricity markets using hourly prices of 2008 (a year with highest prices/volatility)*



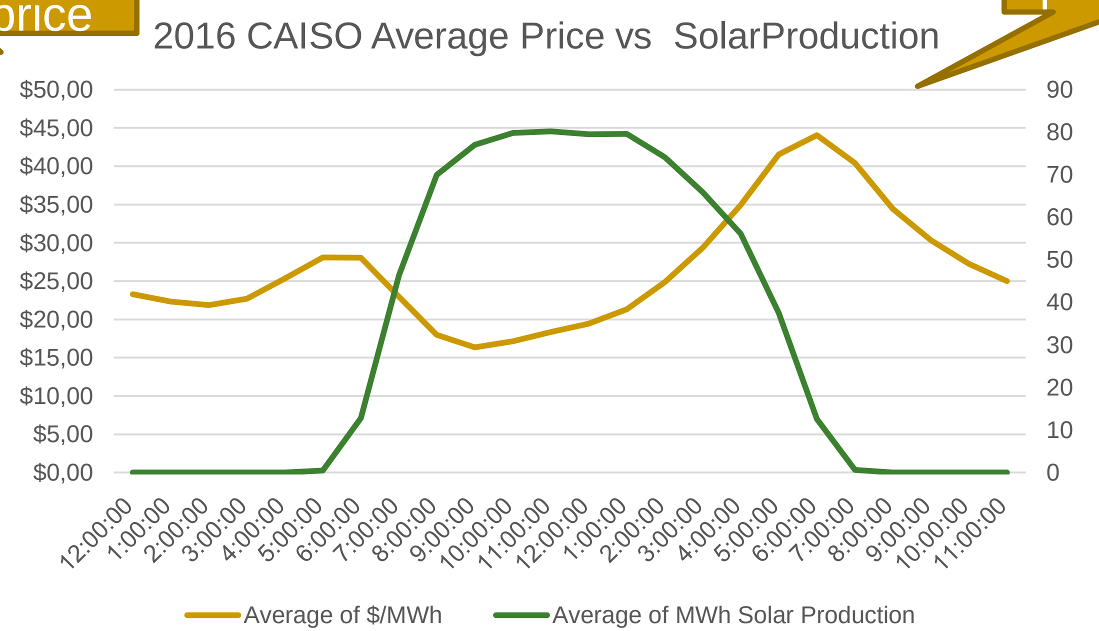
*Kyle Bradbury, Lincoln Pratson, Dalia Patiño-Echeverri, *Economic viability of energy storage systems based on price arbitrage potential in real-time U.S. electricity markets*. **Applied Energy 114 (2014) 512–519**

Hard to recover these costs through pairing of BES with other systems

- We look at the revenues of BES paired with a 110MW PV solar facility in CAISO*

Annual average of DA price

Average Solar production



*Preliminary results from masters project of Duke NSOE student Nicole Miller spring 2018)

Price differentials (1 hour) in CAISO seem promising

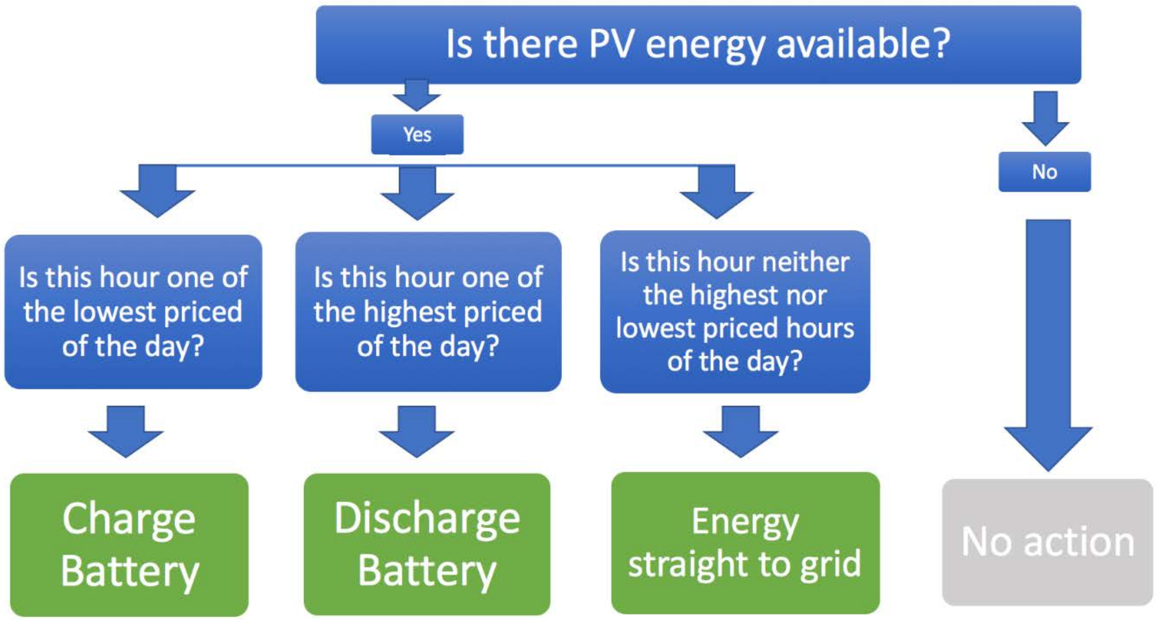
CAISO Hourly Prices Observed in 2016			
Month	Average Min	Average Max	Price Delta
January	$15.21	$41.68	$26.47
February	$13.19	$38.59	$25.40
March	$7.51	$34.54	$27.03
April	$7.27	$38.61	$31.34
May	$14.48	$40.73	$26.25
June	$20.42	$50.76	$30.33
July	$22.33	$55.54	$33.21
August	$25.58	$54.95	$29.37
September	$21.52	$50.45	$28.92
October	$6.97	$56.32	$49.35
November	$12.04	$45.23	$33.19
December	$13.17	$48.30	$35.14

Hard to recover these costs through pairing of BES with other systems

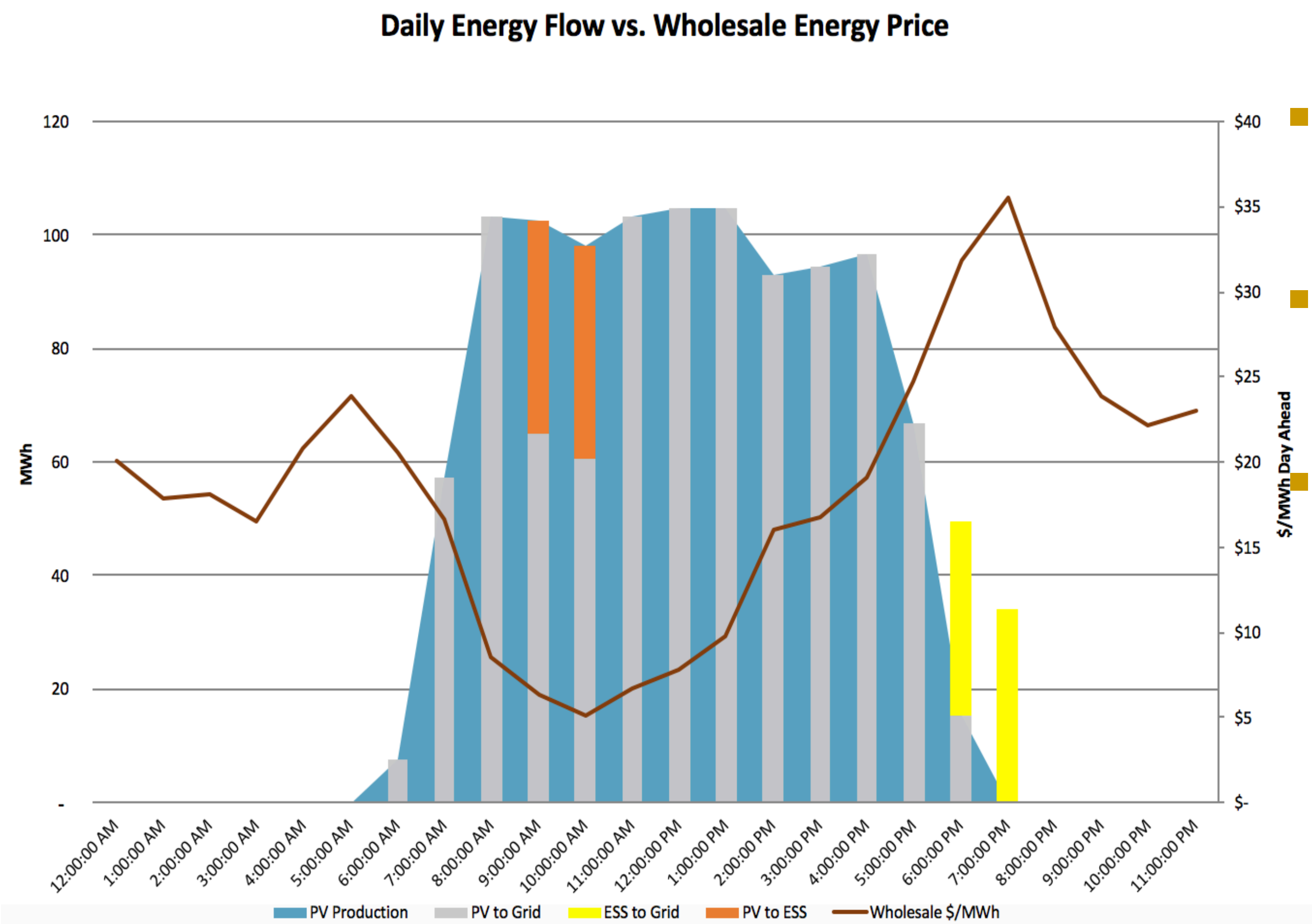
- Follow a simple algorithm for different storage sizes

Assuming :

- - BES 0.5-50 MW / 1-100 MWh
- -$369/kWh BES cost
- -BES round trip efficiency of 80%
- -6% discount rate
- -Taking prices of 2016
  - As they are
  - Increasing differentials



Example: assuming 2MWhrs



- A 0.5MW – 1MWh BES would achieve an NPV of $200K
- Other BES would incur costs in CAISO
- No BES would improve the economics of the solar PV plant PJM or ERCOT
  - Even if price differentials increase by 300%

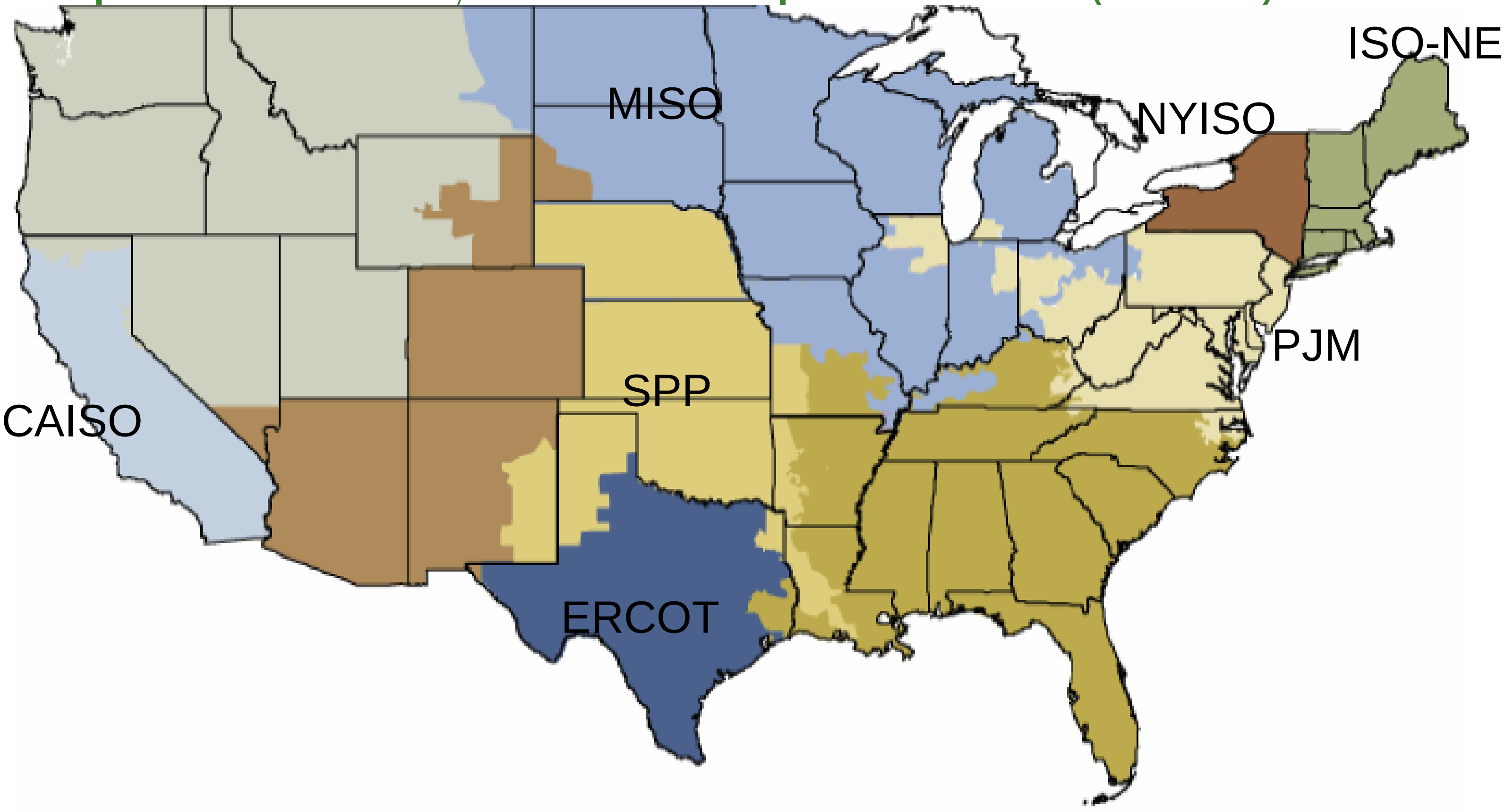
But electricity price arbitrage is only one of many possible revenue streams

- Participation in wholesale organized electricity markets (i.e., ISO/RTO mkts)
  - Energy markets
    - Providing energy, reserves and ramp-capability products
  - Capacity markets
  - Ancillary services

Already possible in several ISO's/RTOs and soon to become the rule everywhere Due to FERC rule 841

However, still unclear how specific RTO/ISO rules will enable all opportunities for ESRs

Regional Transmission Organization (RTO) Independent Systems Operators (ISO)



http://www.ferc.gov/market-oversight/mkt-electric/overview.asp

FERC order 841 – February 15 2018

- Gives 270 days to RTOs/ISOs to create and file a participation model for Energy Storage Resources (ESR)
  - After this, there is 1 year to implement the changes

- ESR already participate in energy and ancillary services
  - but they have to use participation models designed for conventional resources
    - full potential of ESS cannot be utilized

- Defines ESR as “a resource capable of receiving electric energy from the grid and storing it for later injection of electric energy back to the grid”

- Al types of ESS are considered regardless of
  - size (ISOs/RTOs must specify a minimum size not larger than 100kW)
  - storage medium (e.g., batteries, flywheels, compressed air, pumped-hydro, etc.),
  - Or location - Interstate grid, distribution system, or behind the meter

FERC order 841 – February 15 2018 - Guidelines

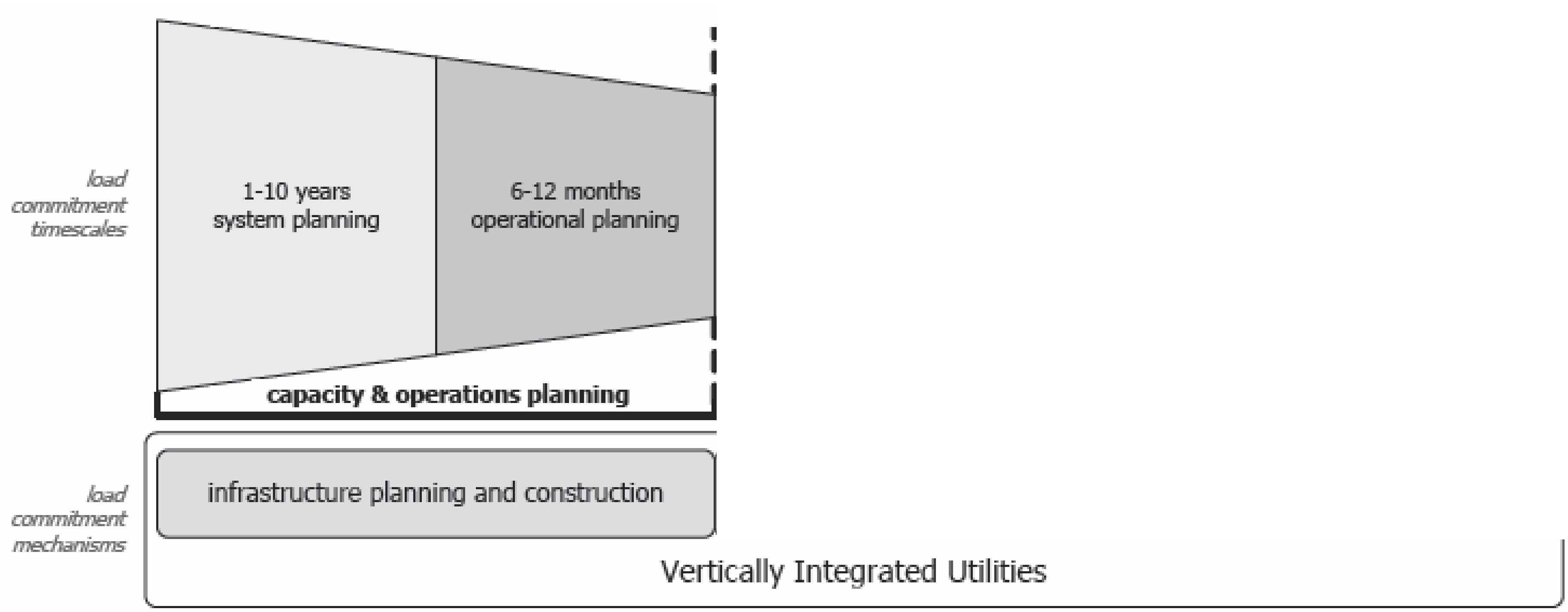
1. Make ESR eligible to provide all **capacity**, **energy**, and **ancillary services** they have the technical capability to provide
   1. RTO's/ISOs can define/modify the technical requirements (e.g., having AGC to provide freq, or minimum run time to provide energy)

2. Allow the dispatch of ESRs and **allow them to set the prices** as a wholesale seller or wholesale buyer
   1. Eligible for makewhole payments when dispatched to buy electricity above its bid

3. Account for the physical and operational characteristics of ESRs through bidding parameters
   - State of Charge (%),
   - Max/Min State of charge(%),
   - Max/min Charge/discharge Limit (MW),
   - Min/max Charge time,
   - Min/max run time,
   - charge/discharge ramp rate

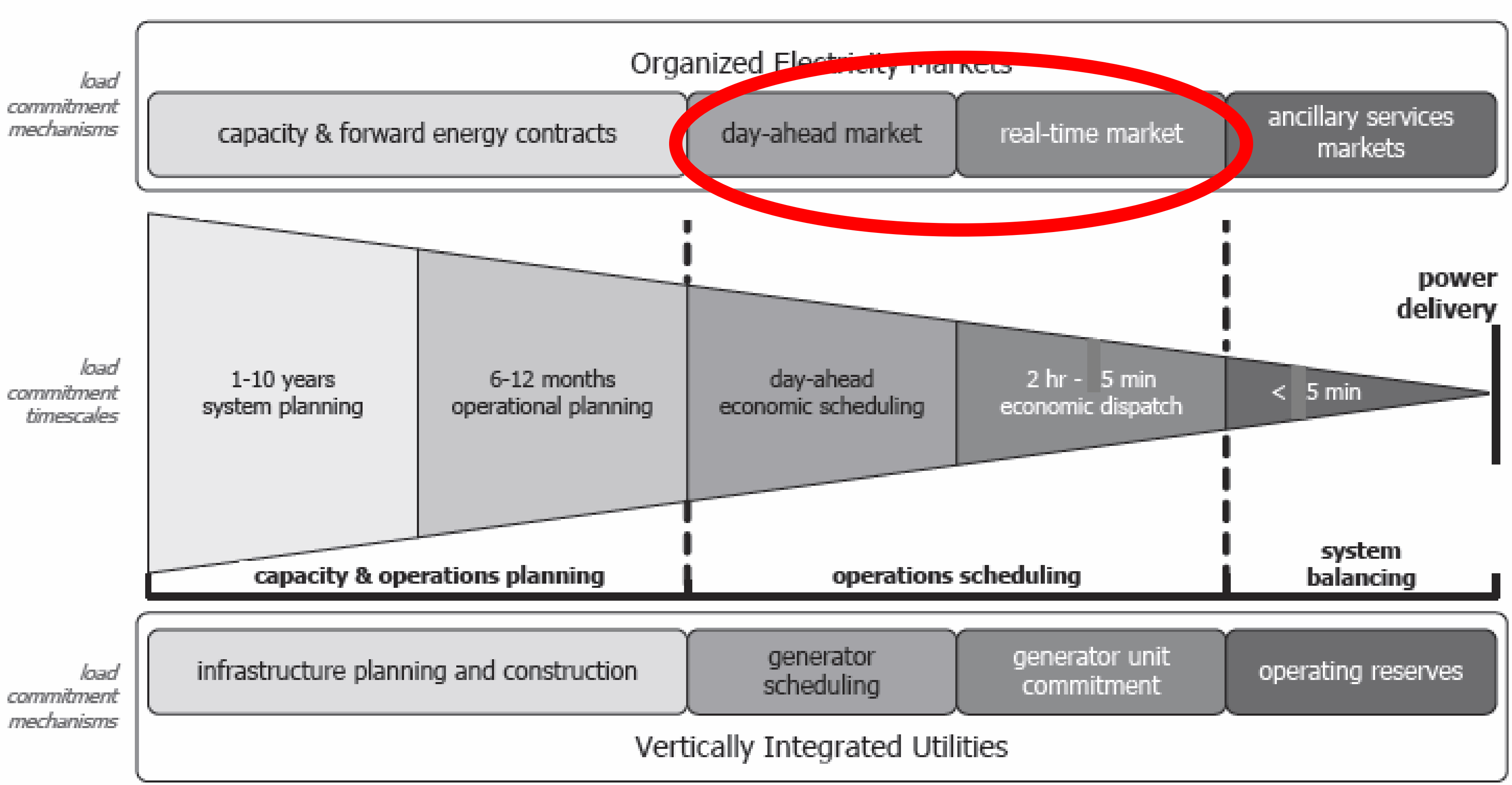
4. Allow ESRs to buy and sell electricity at the LMP
   - but they have to use participation models designed for conventional resources
   - Full potential of ESS cannot be utilized

Balancing Electricity Supply and Demand



Source: US DOE, 2006 – Fig 2.2 – pg 13

Balancing Electricity Supply and Demand



Source: US DOE, 2006 – Fig 2.2 – pg 13

U.S. Energy Market: **Two-settlement** system

- Day-ahead market
  - Hourly clearing prices are calculated for each hour of the next operating day based on:
    - demand bids,
    - generation offers
    - bilateral transaction schedules

generators that receive **Capacity Payments must** submit offers into the day-ahead market (and a schedule of availability for the next 7 days)
Other generators can choose between day ahead and Real Time

Depending on the market there may be one or more other instances of market clearing in between these two

All price calculations based on **Locational Marginal Pricing**

Soon likely to be *Extended* **Locational Marginal Pricing**

- Real time balancing market (spot market)
  - Clearing prices are calculated every five minutes based on actual system operations. Transactions between buyers and sellers are settled hourly; invoices are issued to market participants weekly

Both markets are cleared with a **Unit Commitment** UC and **Economic Dispatch** ED algorithms that **co-optimize** energy, reserves, and ramp-capability prods

- Find how much to commit and dispatch generating resources
- Find the power output produced by each g
- Find the reserves and procured by each g
  - Find the ramp-capability procured by each generator
- Find prices for energy, reserves and ramping products
  - There is a constraint that makes sure that the sum of reserves energy, and ramp capability of a given generator for a time t does not exceed its power limits or ramping capacity
  - The shadow prices of the demand, reserve, and RC are the prices of each
  - Generators are paid for energy, reserves, and RC in DA and RT

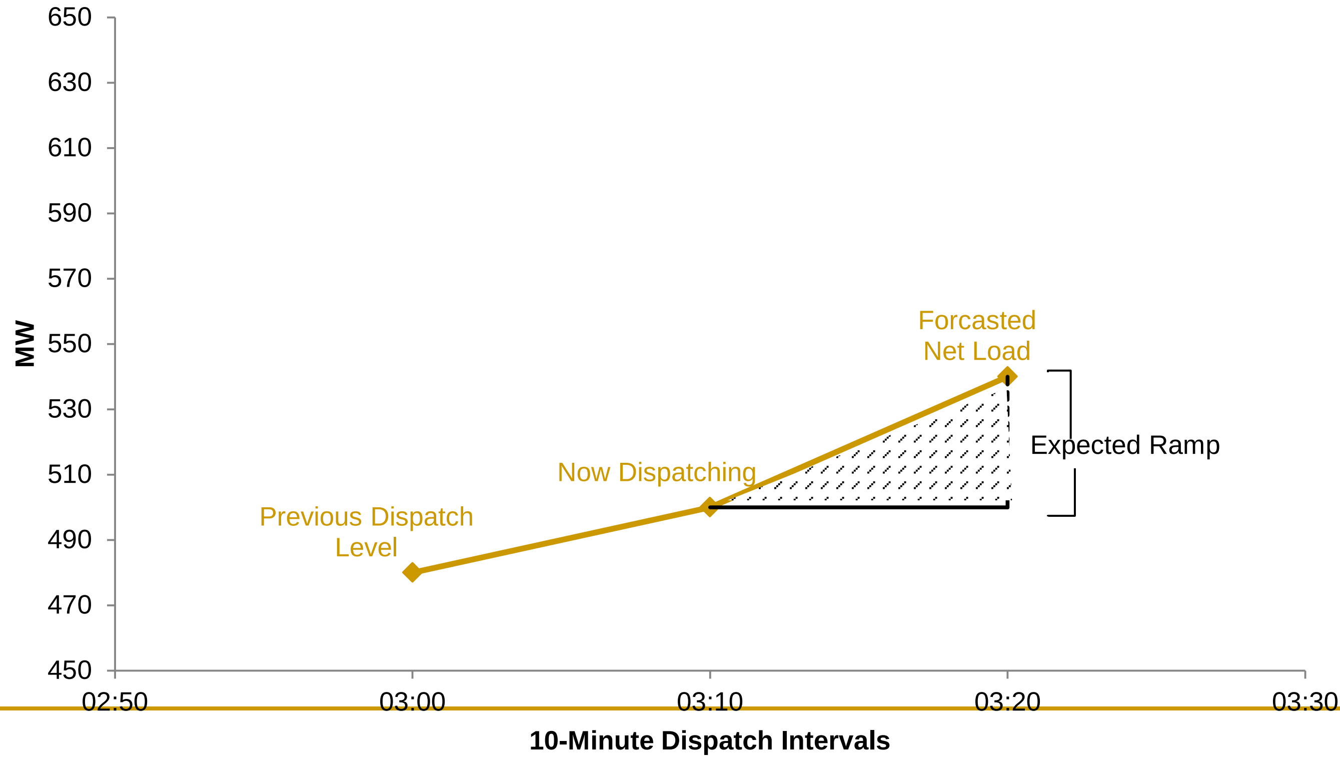
Ramp-capability products

- Implemented in MISO and CAISO in 2016
- Proven to improve the economic, environmental and reliability outcomes of the markets*
  - Reduce instances of energy and reserve shortages in DA and RT
  - Reduce CO_2 emissions
  - Slightly increase prices during non-shortage periods and reduce price spikes
  - Provide a transparent price signal. Prices reflect
    - Marginal opportunity cost of ramping resource
    - Demand curve for ramping showing the value the RTO/ISO is willing to pay for this service

Adam Cornelius, Rubenka Bandyopadhyay, Dalia Patiño-Echeverri. *Assessing environmental, economic, and reliability impacts of flexible ramp products in MISO's electricity market.* **Renewable and Sustainable Energy Reviews 81 (2018) 2291–2298**

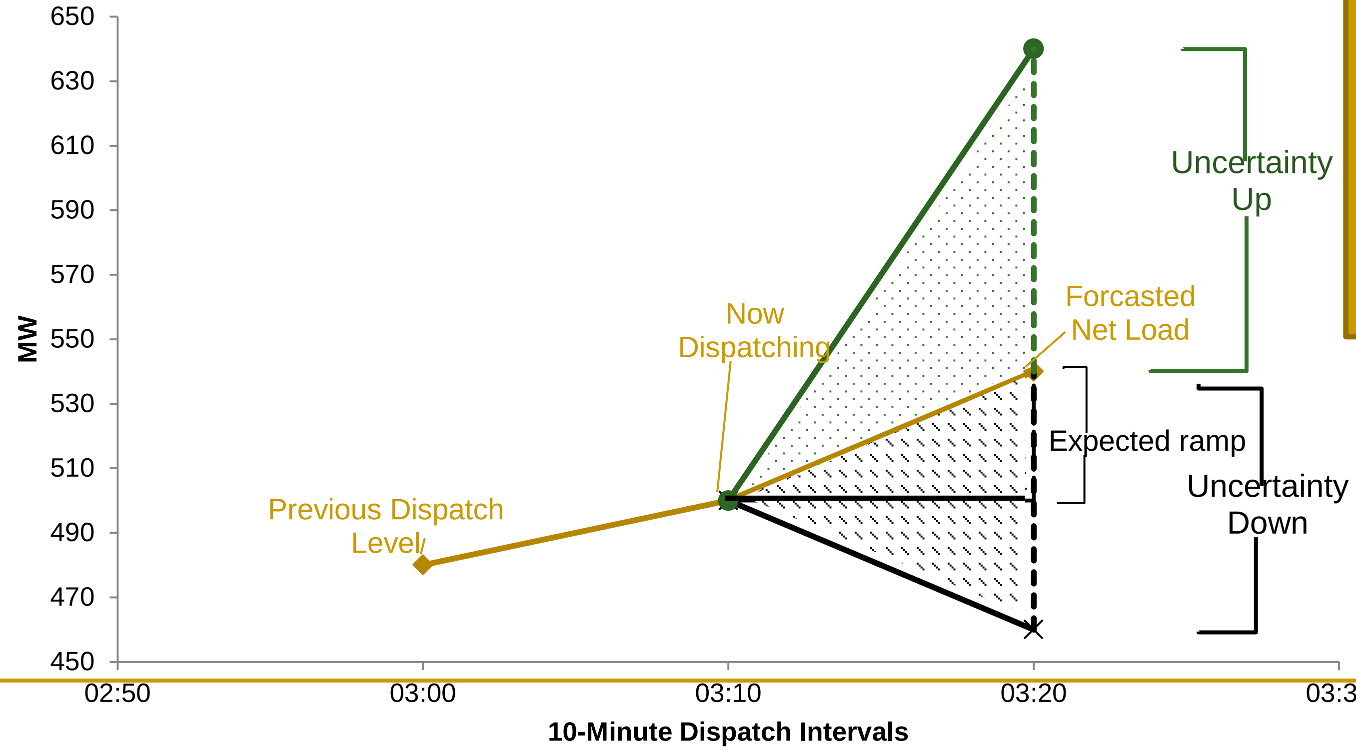
How much ramp capability to procure?

- Consider expected ramp:
  - Dispatching for 3:10 pm
  - Consider net load forecast for 3:20



How much ramp capability to procure?

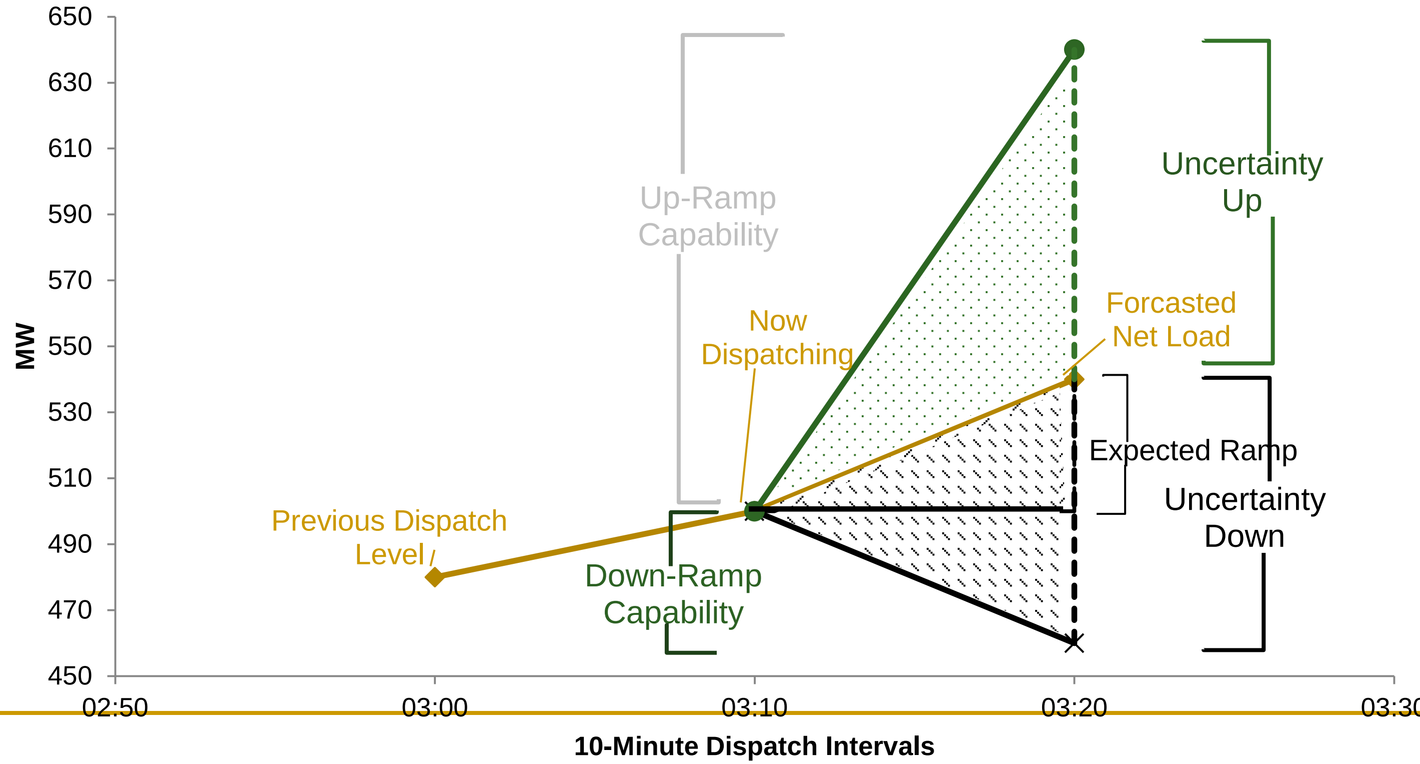
- consider uncertainty surrounding forecast in both directions



It is chosen to be 2.5 standard deviations from historical analysis

How much ramp capability to procure?

- Procure enough Up-Ramp and Down Ramp Capability to meet uncertainty levels
- Quantity will vary by season & time of day



Day Ahead Unit Commitment (with ramp)

Planning Period: 24 hours
Interval: 1 hour

Minimize:

Energy Costs + Spinning Reserve Costs + Startup Costs + Fixed Costs + OverGenerationPenalty + UnderGeneration Penalty + Scarcity of Reserves Penalty – Benefits of Procured URC – Benefits of Procured DRC

Subject to:

- DispatchableGen + Stochastic Gen +UnderGen - OverGen-= Forecasted Load
- Reserves Available >= Reserves Required
- System URC Procured <= URC Target
- System DRC Procured <= DRC Target
- Sum of Generator URC >= System URC Procured
- Sum of Generator DRC >= System DRC Procured
- Generator constraints
  - Ramp rates
  - Min up/down time
  - Min/Max Generation

Output:

- Planned Hourly Generator Schedules for:
  - Commitment (on/off)
  - Energy Produced
  - Spinning Reserves Provided

Real-Time Economic Dispatch (with flexiramp prods)

Miso RTED is 5 min but our wind data is 10 min

Benefits or URC and DRC are lower than over or under generation penalty, or scarcity of reserves penalty, so RC is **third** in priority

Planning Period: 10 Minutes
Interval: 10 Minutes

Minimize:

Generation Costs + No load costs + Spinning Reserve Costs + OverGenerationPenalty + UnderGenerationPenalty +SpinningReservesScarcityPenalty – Benefits of Procured URC – Benefits of Procured DRC

Subject to:

- DispatchableGen + Stochastic Gen +UnderGen - OverGen-= Foreca
- Reserves Available >= Reserves Required
- System URC Procured <= URC Target
- System DRC Procured <= DRC Target
- Sum of Generator URC >= System URC Procured
- Sum of Generator DRC >= System DRC Procured
- Generator Parameters not violated
  - Ramp rates
  - Min up/down time
  - Min/Max Generation

Targets are determined based on expected ramp and historical variability of ramp

Shadow prices of URC and DRC constraints are the payments to generators re-dispatched and reduce the need for plift costs

Output:

- Generator Dispatch levels for:
  - Energy Produced
  - Spinning Reserves Available
  - URC/DRC
- Market Clearing Price for
  - Energy
  - Spinning Reserves
  - URC/DRC

Does co-optimization of energy and ancillary services (reserves and rc products) hinders ESRs participation

- Neither MISO or CAISO ask for specific bids for RC products
  - Generators are assumed to agree to provide any combinations of energy, reserves and rc deemed optimal by the ISO
  - Does this mean that ERS need to submit an energy bid to be paid for RC products?
    - Changing the approach of co-optimizing energy and reserves requires costly software changes
    - FERC encourages RTO/ISO to look at this
    - Our research shows that

Capacity Markets

- ISOs/RTOs should allow ESR to de-rate their capacity if needed to meet minimum run times
  - For example a 10MW / 20MWh ESR can offer 5MW of capacity into a capacity market with a 4-hour minimum run-time
  - ESRs are still subject for penalties for not performance
  - De-rating should not be confused with with-holding

- ISOs/RTOs can propose their own rules
    - NYISO: Energy Limited Resource model → Limits commitments of ESR to one four-hour interval per day

- Capacity markets no longer look at just resource adequacy
  - CAISO now asks that a certain amount of contracted capacity be **flexible resources**
    - Can respond to real-time instructions
    - Can start at least twice daily
    - Is responsive enough to meet anticipated ramp needs

Revenue streams for ESR and challenges

ESRs can recover costs through

- Market mechanisms
  - DA and RT markets:
    - Selling energy, reserves, ramp-capability
  - Capacity markets
    - Getting capacity payments
  - Ancillary services
    - Frequency regulation
    - Black start service
    - Reactive power / voltage support
- Cost-based rates
  - Allowing deferral of investment in transmission and distribution infrastructure

Potential for market distortion ?

Ownership by regulated utilities (LSE)?

Conclusions

Variability and Uncertainty of VERs motivate design changes in U.S. markets that may favor the economics of ESRs

- Flexibility is valued and remunerated
  - RC products is one example

But

- Price differentials may decrease
  - Reduce revenue streams for ERS
- Non-trivial modifications to the DA/RT market clearing may be needed to guarantee ERS do not face any participation barriers

Obrigada!!

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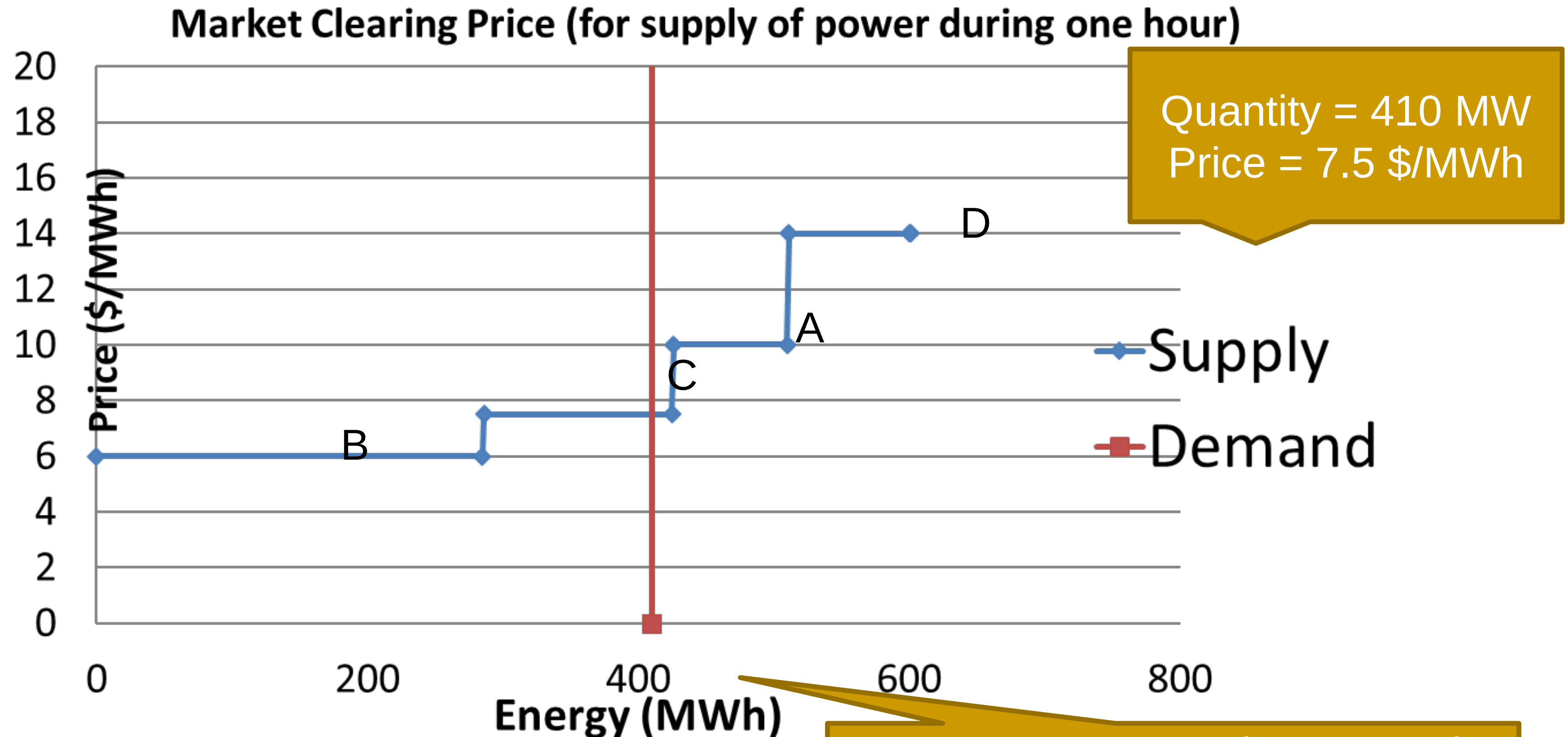
Clearing the market

1. Bids to sell: stack in ascending order by price

Bids to sell	Company	Quantity (MW)	Price ($/MWh)	Cumulative bids (MW)
	B	285	6	285
	C	140	7.5	425
	A	85	10	510
	D	90	14	600

2. Draw a supply curve
3. Draw demand curve
4. Find price and dispatch

Uniform price auction

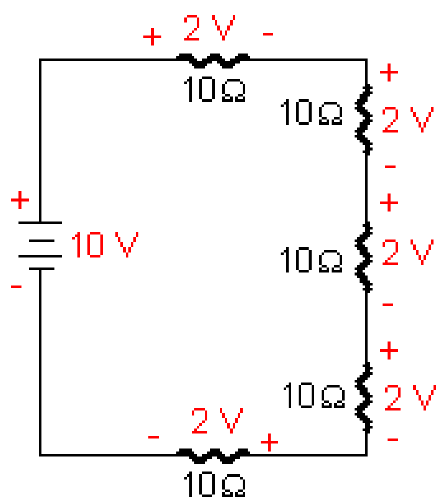


But generators are in a network and power flows according to Kirckoff laws !!

Kirchhoff Voltage Law (KVL)

- Sum of voltage drops around any closed loop in a circuit must equal the applied voltages

E.g. The sum of voltage drops across all the branches of any loop must be equal to zero



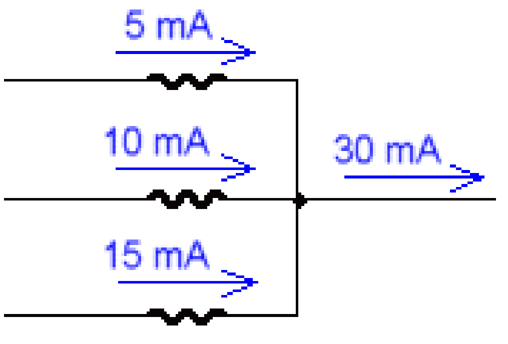
Analogy:
Closed electric loop=water fountain
Battery = water pump
rise in voltage = rise elevation

Or

- The voltage drops across parallel paths must be equal

Kirchhoff Current Law (KCL)

- The sum of all the currents entering a node must be equal to the sum of all the currents leaving this node
- Active and reactive power must be in balance at each node:
  - Generation + Imports – Exports – Consumption = 0



Of course this is an AC system:

- Impedance: $|Z| = \sqrt{R^2 + (X_L - X_C)^2}$
- Generalized Ohms law for AC circuits: $I_{\max} = \frac{V_{\max}}{Z}$
- But we will simplify (as ISOs do to clear the mkt)

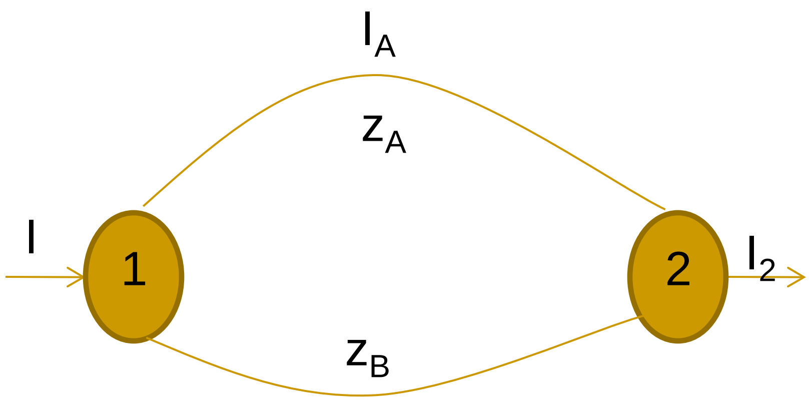
Resistance in the path is much smaller than the reactance, so the impedance is aproximately equal to the reactance (R is much smaller than X, so Z~=X)

Ignore the flow of reactive power

Ignore thermal losses in the network

Network constraints are expressed as maximum capacity for active power transfer in MW

Example 1: Find current flow across each branch



Power flow is equal to injected power times the reactance of the complementary path divided by the total reactance of all paths

1. KCL→ Sum of all currents entering a node = the currents exiting the node:

$$I = I_A + I_B$$

2. Ohm's law for AC systems

$$V_m = I_m Z$$

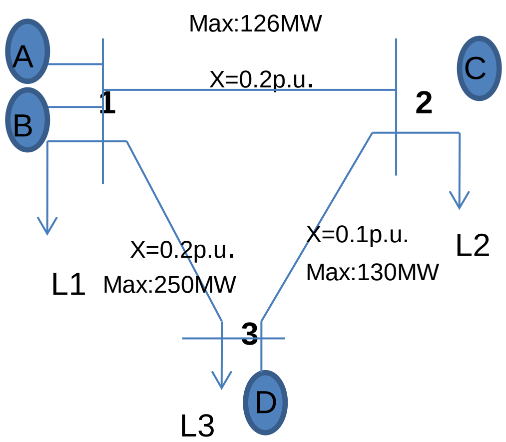
3.KVL→ Voltage drops across parallel paths are equal:

$$V_{12} = I_A Z_A = I_B Z_B$$

Substituting 1 into 3 we find

$$I_B = I \frac{Z_A}{Z_A + Z_B} \qquad I_A = I \frac{Z_B}{Z_A + Z_B}$$

Now consider the grid



Generator	Marginal Cost ($/MWh)	Maximum Generating Capacity (MW)
A	7.5	140
B	6	285
C	14	90
D	10	85

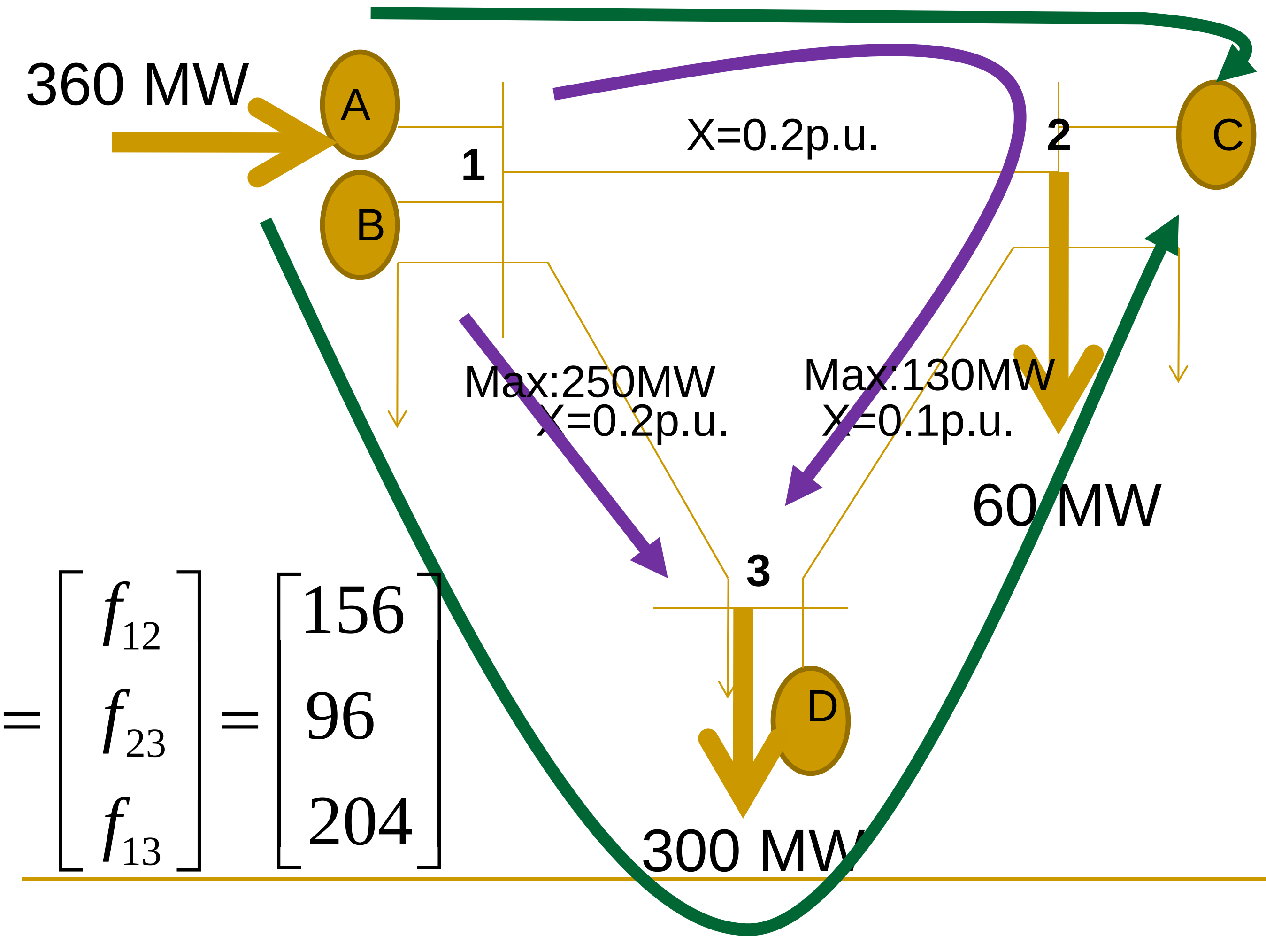
Unconstrained dispatch:
-Generate 285MW from B
-Generate 125MW from A

Price: $7.5/MWh at all nodes

Feasible? We need to find flows

Assume:
L1 = 50MW
L2 =60MW
L3 = 300MW
a) What is the unconstrained dispatch? What is the price if? Is it feasible?
b) What is the security constrained economic dispatch? What is the price?

Example 4: find Power Flow corresponding to unconstrained dispatch



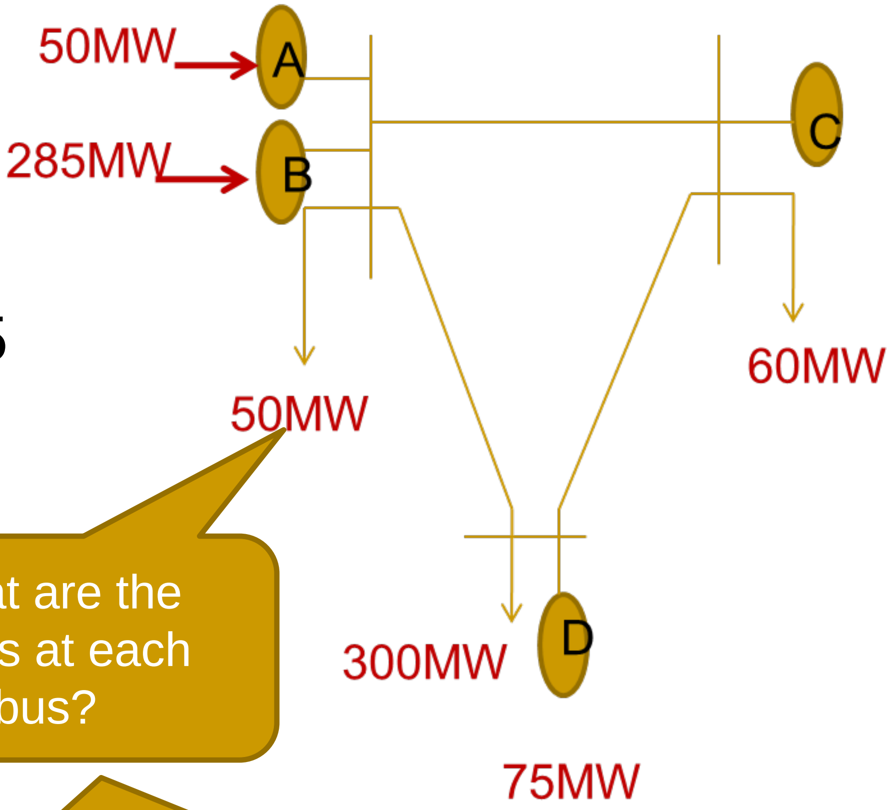
$$X = \begin{bmatrix} f_{12} \\ f_{23} \\ f_{13} \end{bmatrix} = \begin{bmatrix} 156 \\ 96 \\ 204 \end{bmatrix}$$

Locational Marginal Price (LMP)

- LMP = the minimum cost of supplying an additional MW of electricity at that node
- Loads pay the LMP at their node of withdrawal
- Generators are paid the LMP at their node of injection
- What happens to the difference ?
  - That is a revenue of transmission congestion
    - Distributed to those who pay for the costs of transmission lines (typically through FTR markets)

Security constrained economic dispatch:

- Injection at node 1: 285
- Withdrawal at node 2: 60
- Withdrawal at node 3: 225



- Generation B: 285
- Generation A: 50
- Generation C: 0
- Generation D: 75

What are the LMPs at each bus?

They are no longer 7.5$/MWh at each node because there are transmission constraints

Need to learn definition of **Marginal Generator**

Definition: Marginal generator

Characteristics

1. A partially loaded generator

2. Could vary output to make feasible supply of the next MW of load demanded in the system
   - Increase output
   - Or decrease output to alleviate transmission congestion

- How many marginal generators ?
  - If m binding constraints then m+1 marginal generators

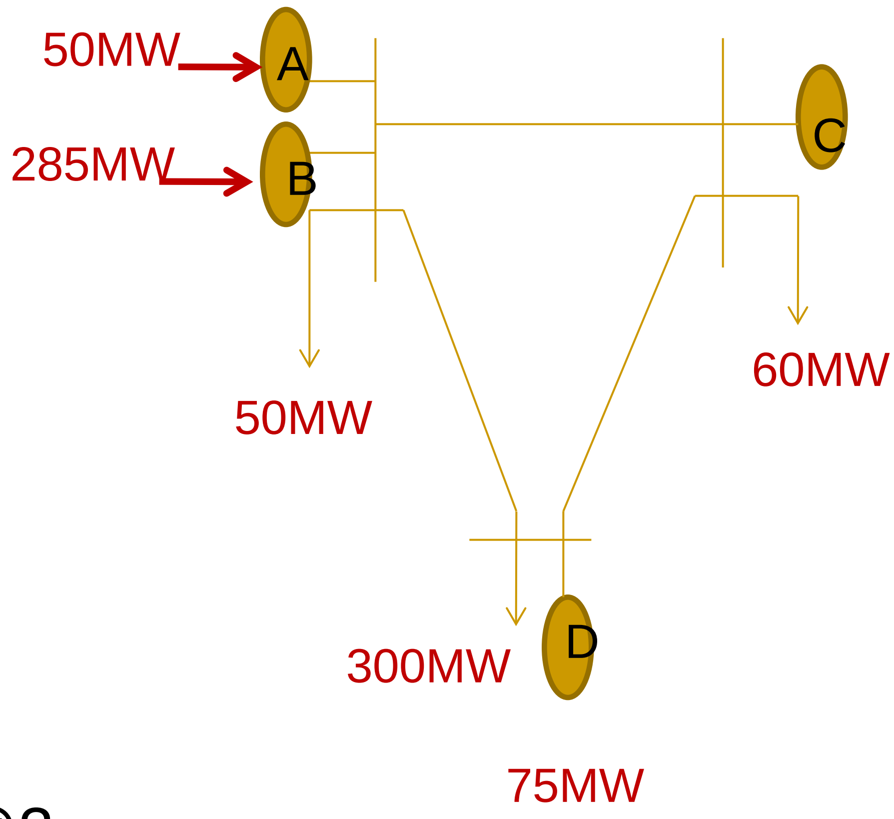
Calculating LMP

- Nodes with a marginal generator
  - LMP = Marginal cost of the marginal generator

- Nodes without a marginal generator
  - LMP = Linear combination of the LMP at other nodes
  - Since next MW at node might be produced by increasing production at some marginal generators and decreasing it at others, LMPs can be lower than the MC of the marginal generators

Calculating LMPs

- Marginal generators:
  - A, D
- LMPs=?
- LMP @ 1: 7.5 $/MWh
- LMP @ 3: 10 $/MWh
- LMP @ 2 = ?
- Linear combination of
  - LMP @ 1 and LMP @3
  - Find cheapest way to meet next MW of load at 2 without increasing flow on congested line



Solution: Calculation of LMP at Node 2:

To provide 1MW at bus 2 without violating capacity limits of the congested line 1-2 we need to:

- Increase Generation at 3 by 1.5MW,
- decrease generation at 1 by 0.5MW

LMP @ 2:

1.5*10$/MWh - 0.5*7.5$/MWh =
11.25 $/MWh

Method 2: Using optimization to find power flows

This is called:
Optimal Power Flow (OPF)

- Decision variables?
  - Generation $G_{A,}\ G_{B,}\ G_{C,}\ G_D$
  - Power flow on each line $f_{12,}\ f_{23,} f_{13}$
- Objective function?
  - Minimize cost: $\min \sum_{i=1}^{N_G} C_i(G_i)$
- Constraints?
  - Total Generation equals total load
  - Generation is within limits → for all generators
  - Power bus balance equation→ for all buses G_i-L_i-…+…=0
  - KVL around the loop $x_{12}f_{12}+x_{23}f_{23}-x_{13}f_{13}=0$
  - Flows on lines do not exceed capacity →for each line

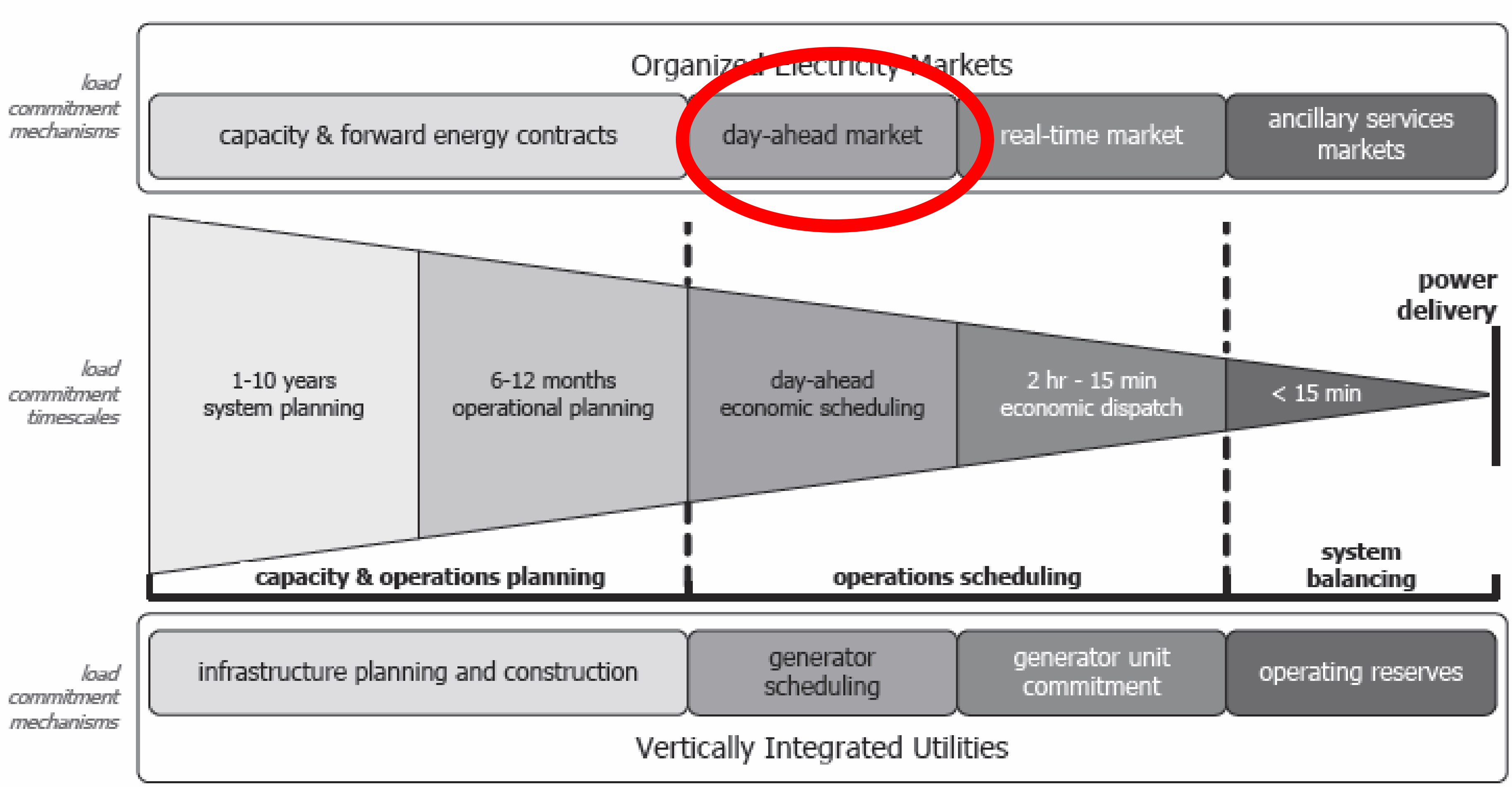
Calculation of LMPs accounting for thermal losses

- Why should losses be considered?
  - Losses increase with
    - Longer lines
    - Lower voltages
    - Higher current (higher load)

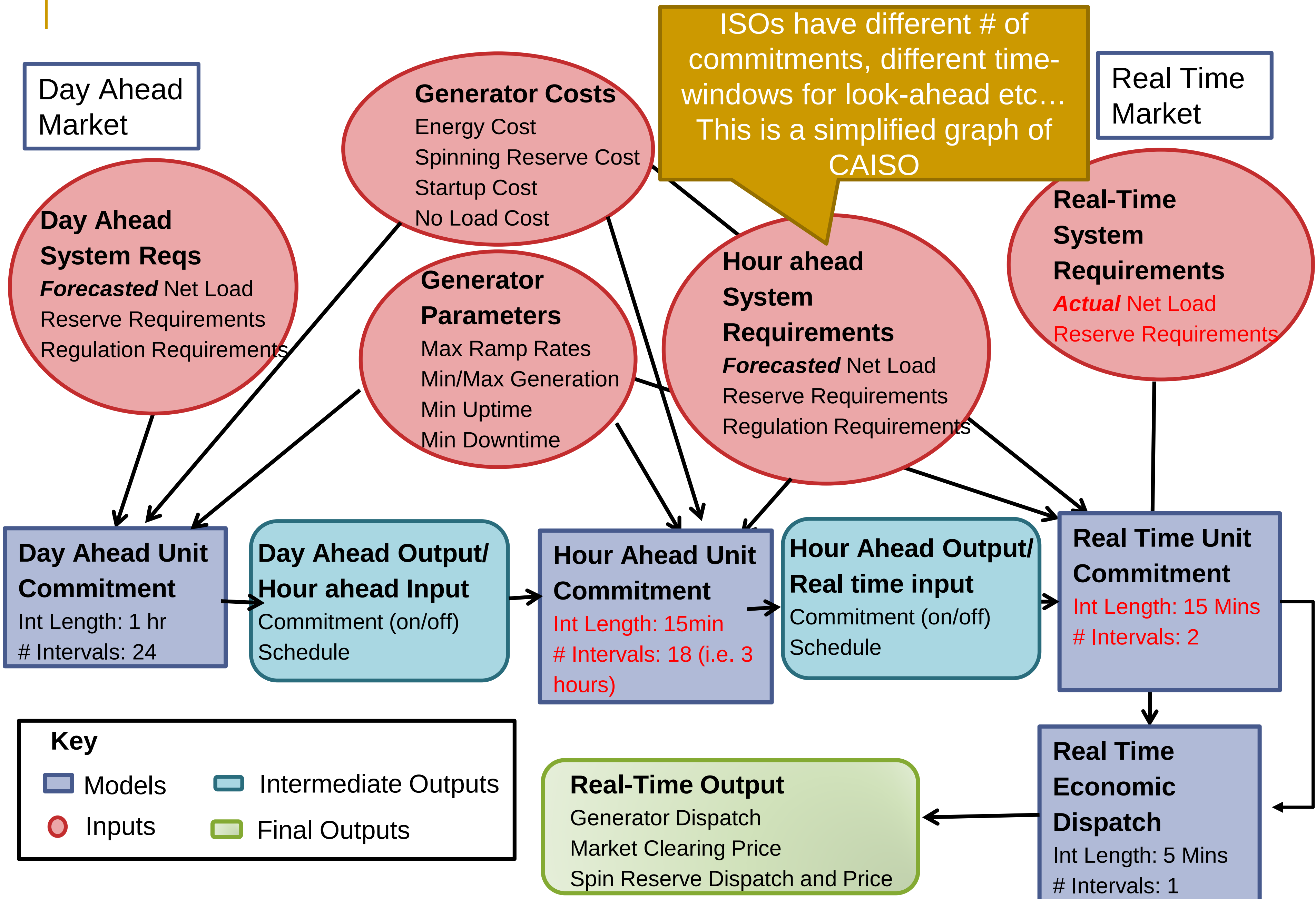
  - A *security constrained economic dispatch* that does not consider losses is less than optimal

LMP = generation marginal cost + transmission congestion cost + marginal losses cost

Balancing Electricity Supply and Demand



Market Clearing: Unit Commitment/Economic Dispatch Model



Market Clearing – Day Ahead Unit Commitment

Planning Period: 24 hours

Decision variables:

- Planned Hourly Generator Schedules for each hour of the planning period:
  - Commitment (on/off)
  - Energy Produced
  - Spinning Reserves Provided

Minimize:

Energy Costs + Spinning Reserve Costs + Startup Costs + Fixed Costs + OverGenerationPenalty + UnderGeneration Penalty + Scarcity of Reserves Penalty

Subject to:

- DispatchableGen + Stochastic(wind and solar)Gen +UnderGen - OverGen-= Forecasted Load
- Reserves Available >= Reserves Required
- Generator constraints
  - Ramp rates
  - Min up/down time
  - Min/Max Generation

Market Clearing – Day Ahead Economic Dispatch

Planning Period: 24 hours

Assume units are on or off as prescribed by the Unit Commitment

Decision variables:

- Planned Hourly Generator Schedules for each hour of the planning period:
  - Energy Produced
  - Spinning Reserves Provided

Minimize:

Energy Costs + Spinning Reserve Costs + Startup Costs + Fixed Costs + OverGenerationPenalty + UnderGeneration Penalty + Scarcity of Reserves Penalty

Subject to:

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- Reserves Available >= Reserves Required
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  - Ramp rates
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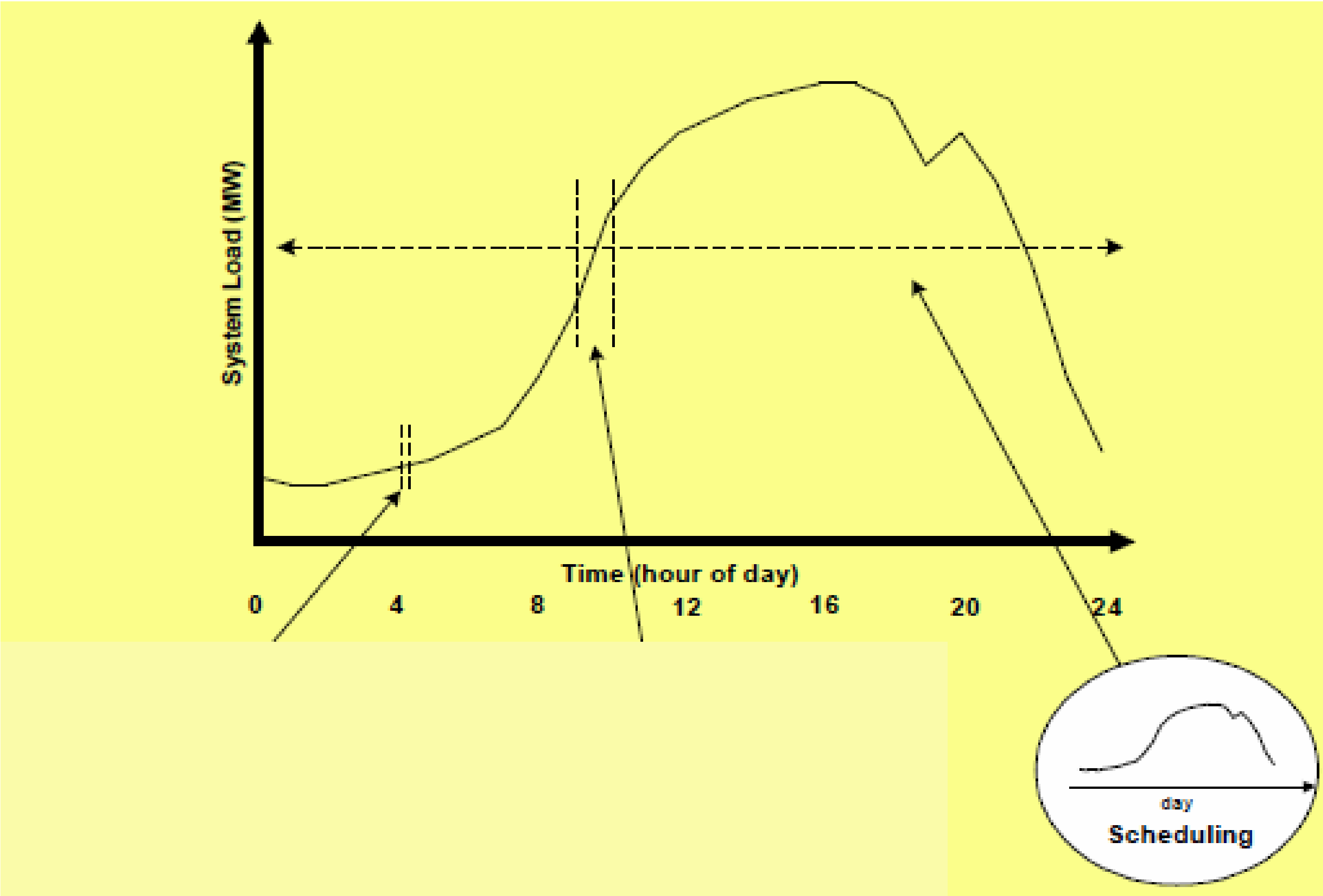
  - Min/Max Generation

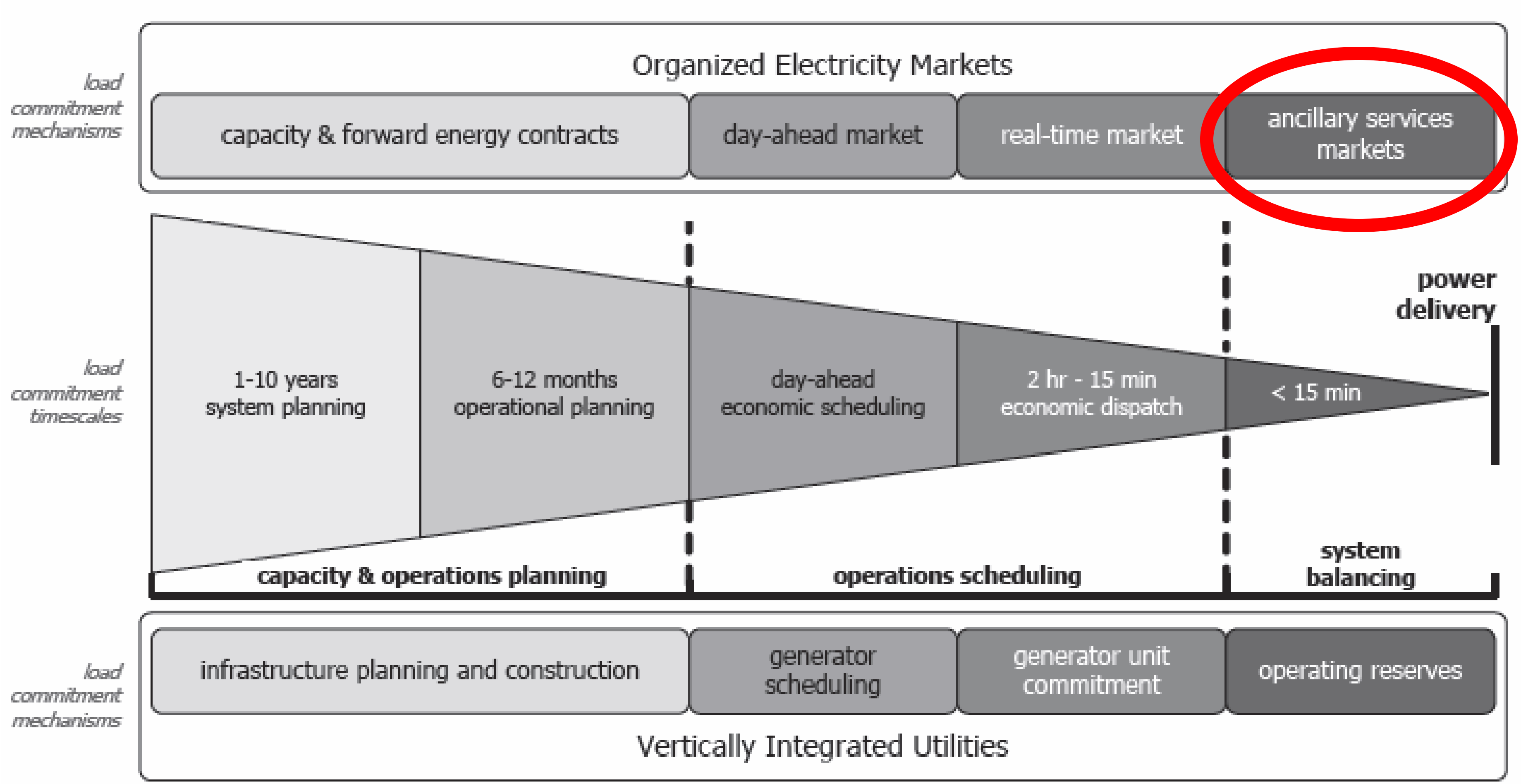
There is a power balance constraint for each node

Shadow price of each is LMP

Balancing Electricity Supply and Demand



Balancing Electricity Supply and Demand



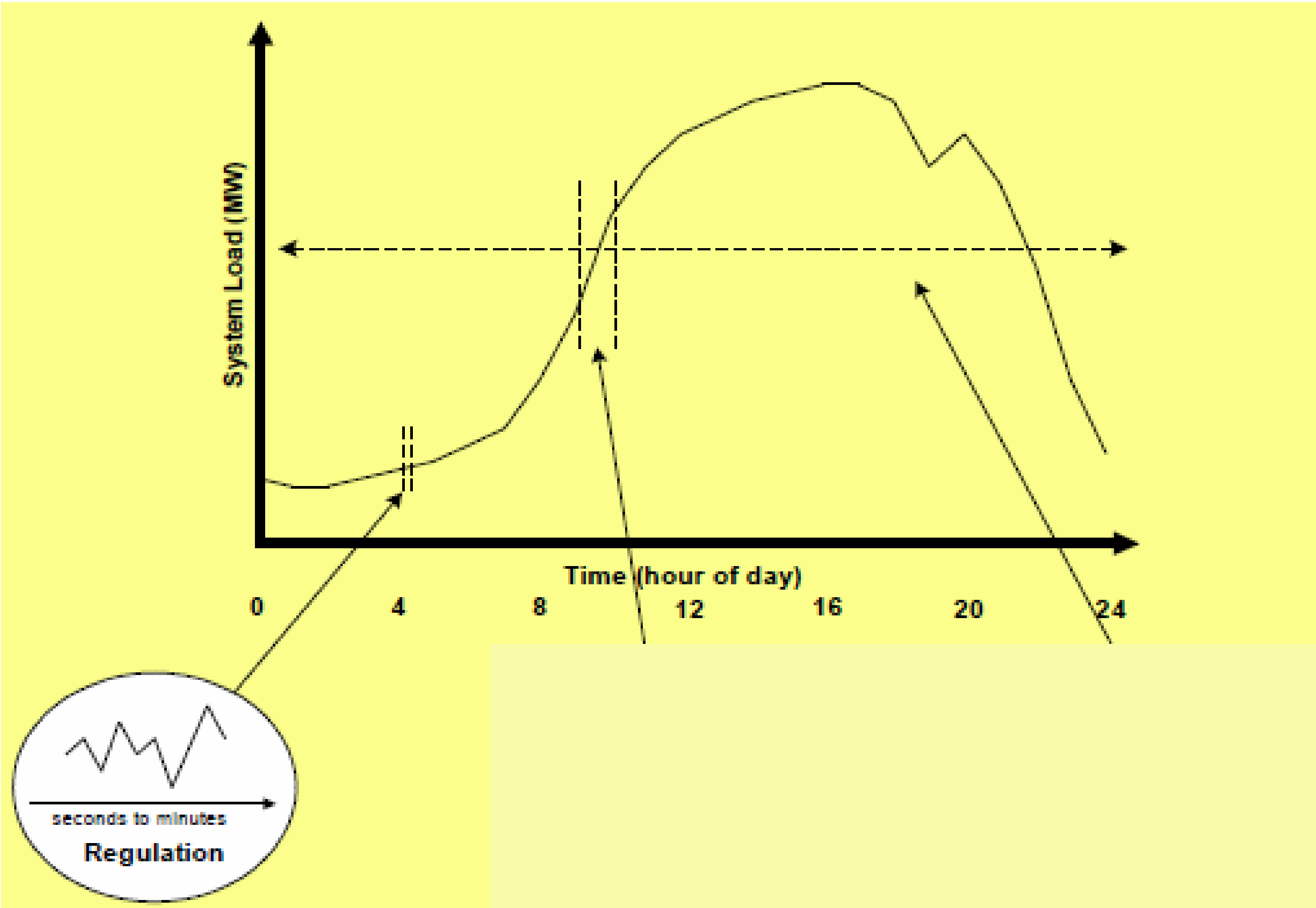
Ancillary services

- Preventive services
  - Frequency Regulation
  - Load following
- Reserve services
- Emergency
  - Black start-capability

Regulation service

- Handles:
  - Sudden fluctuations in the load
  - Small unintended variations in generation
- Keeps frequency close to normal
- Provided by units that have an AGC

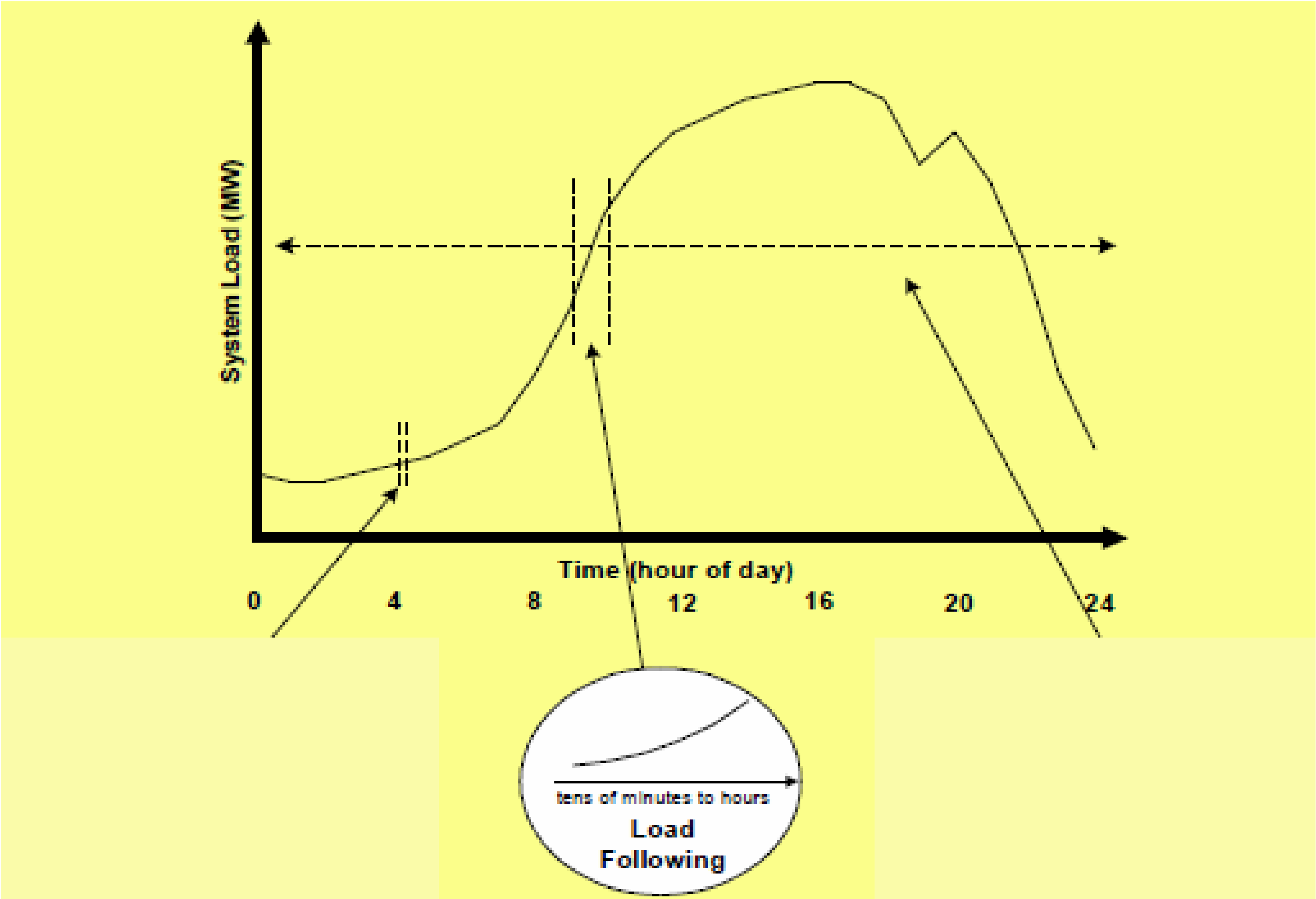
Balancing Electricity Supply and Demand



Load following service

- Handles
  - Slower fluctuations in load
  - Intra period load fluctuations (that are usually neglected by the energy market)
- Provided by generating units (or storage facilities) with fast ramp-rates
  - Spinning reserves
  - Supplemental reserves

Balancing Electricity Supply and Demand

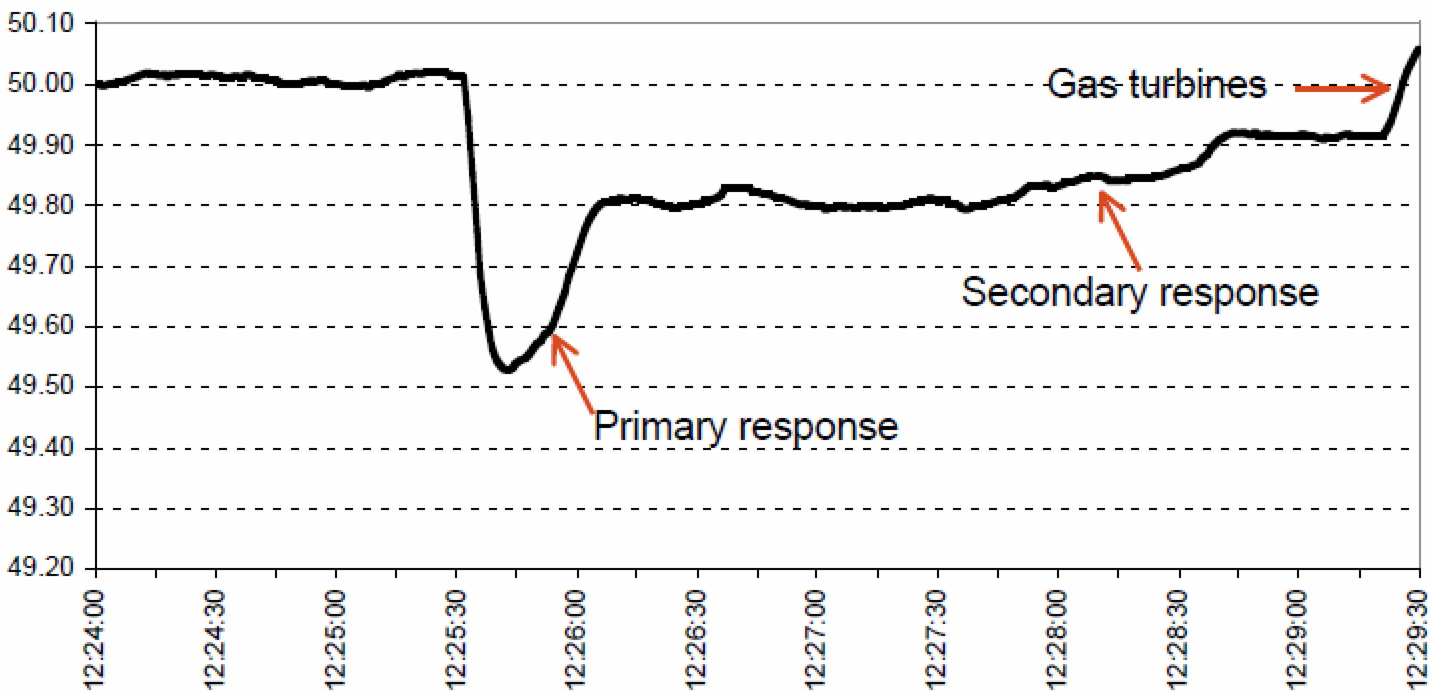


Reserve services

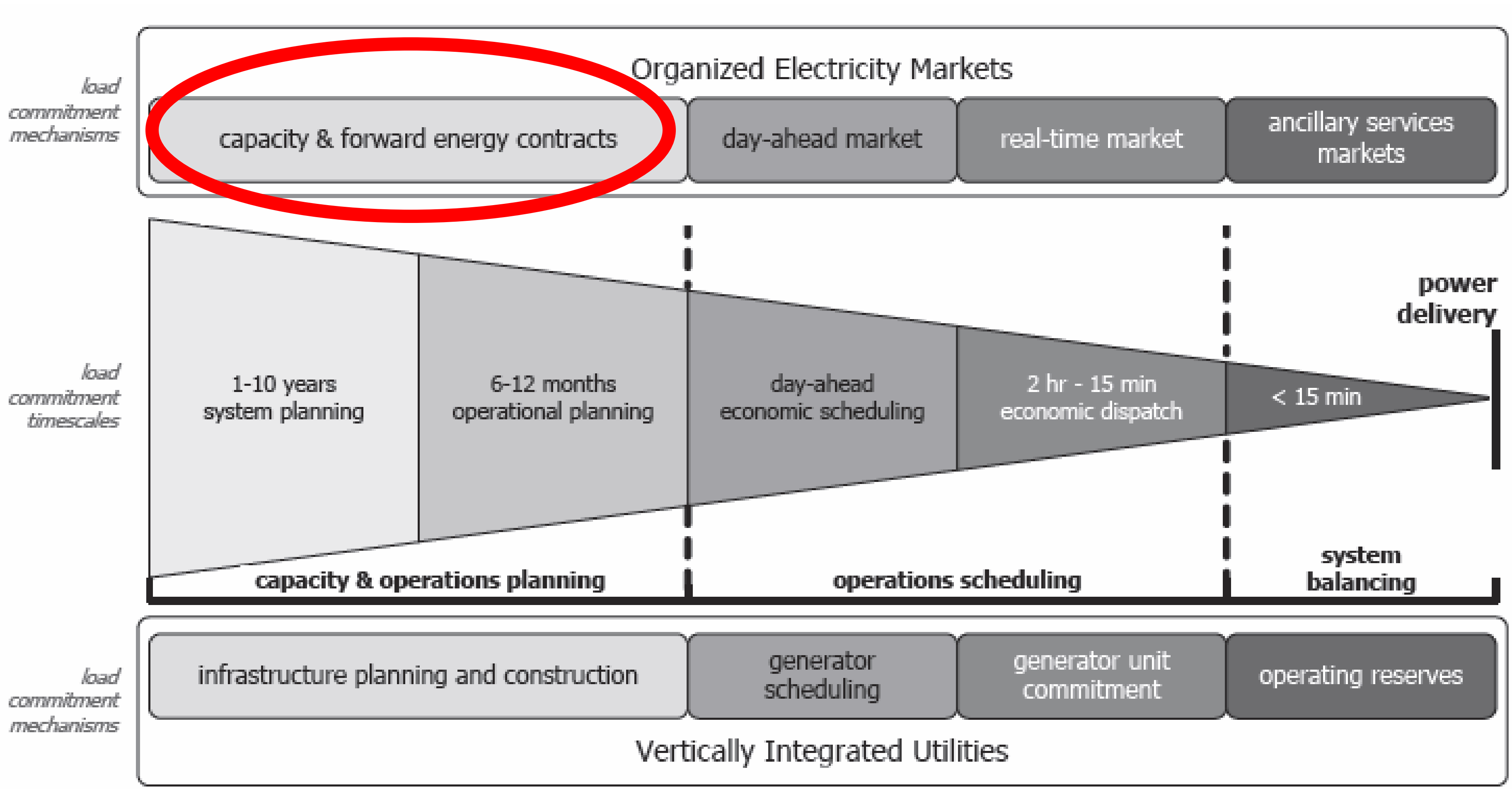
- Handle
  - Large and unpredictable generation deficits (generators and transmission outages)

- Types of reserves
  - Spinning reserves
    - Primary: Available withing10secs and sustainable for 20secs
    - Secondary: Available within 30secs and sustained for 30 min
  - Supplemental reserve: can replace spinning

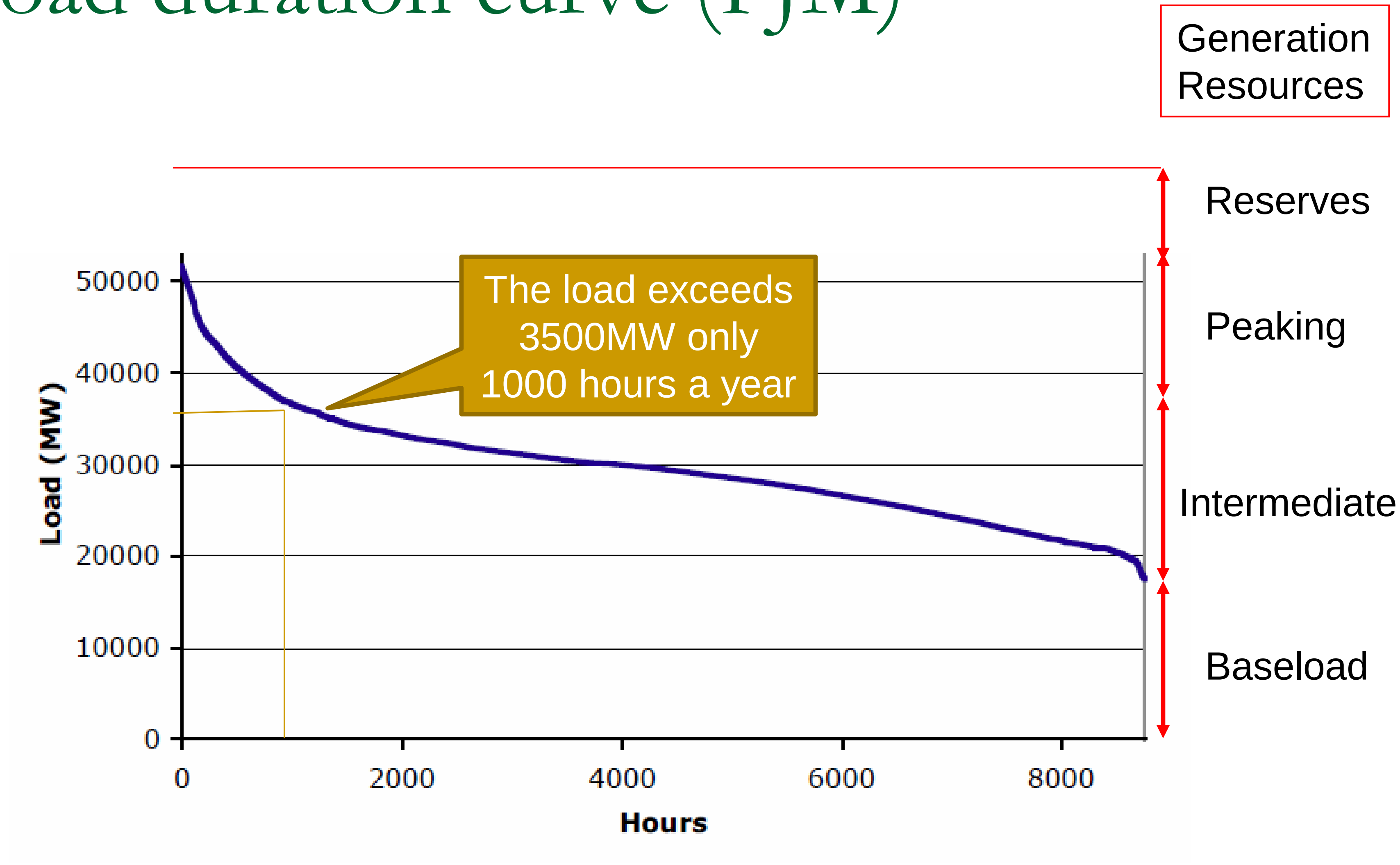
System Response to a generator outage



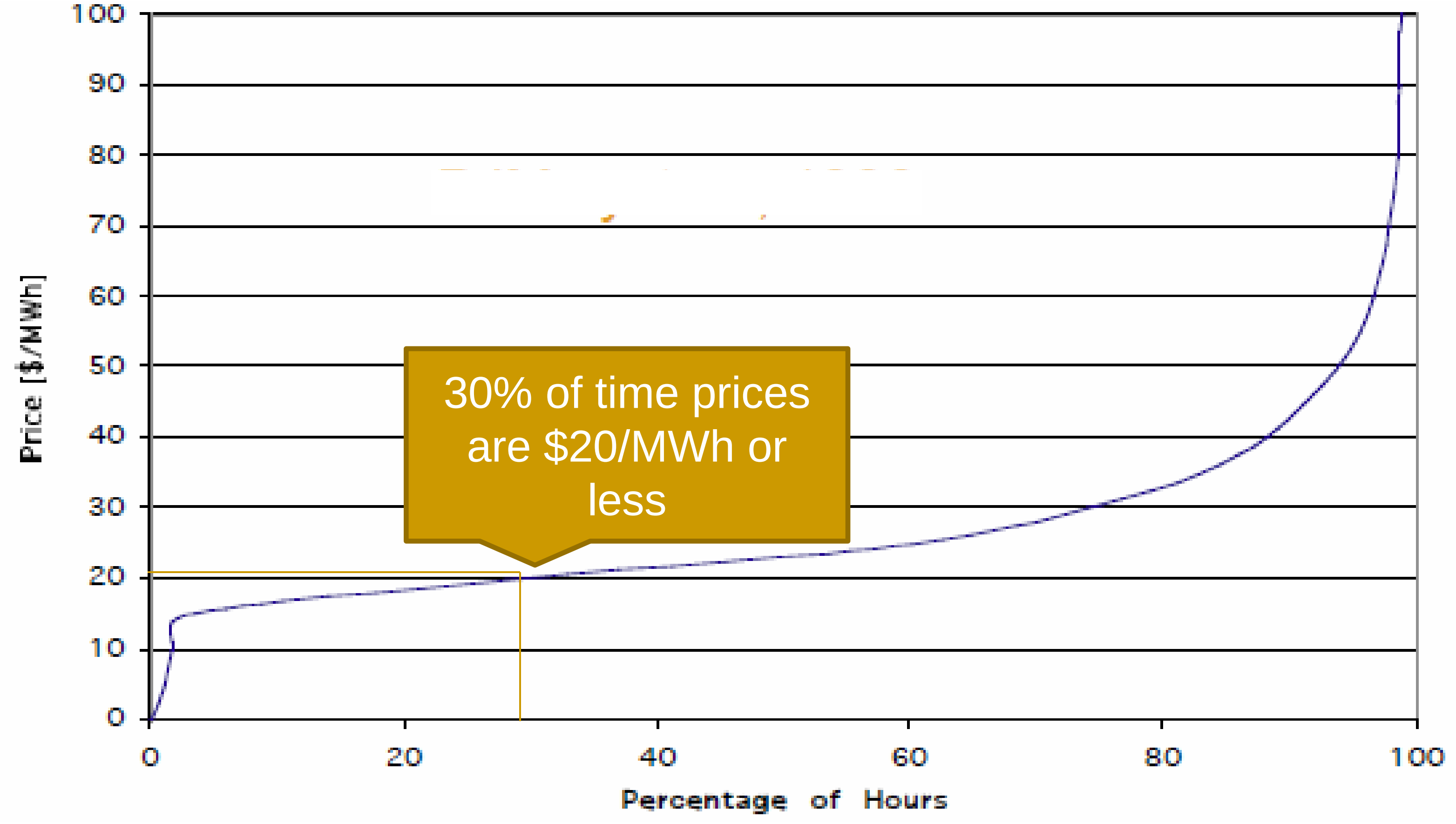
Balancing Electricity Supply and Demand



Load duration curve (PJM)



Price duration curve



Implications of the load duration curve

- Market price is set by the marginal cost of marginal generator
  - This is the most expensive generator needed at that hour to meet demand
- Infra marginal generators collect an economic profit because their marginal cost is less than the market price
  - Economic profit pays the fixed costs
- Marginal generator will not recover its fixed cost if price = MC
  - So it needs to incorporate them in its bid (Price=MC+Fixed cost)
  - This is why there are price spikes
- To avoid very high price spikes…
  - Price caps are implemented by ISOs
- But, price caps do not allow marginal generators to recover their Fixed costs So to ensure generation resource adequacy .. .NEED capacity payments !!
- Or need to allow for an scarcity adder to the real time energy price (ERCOT ORDC)

Without any of these, there will not be adequate investment in generation capacity!!

Capacity Market

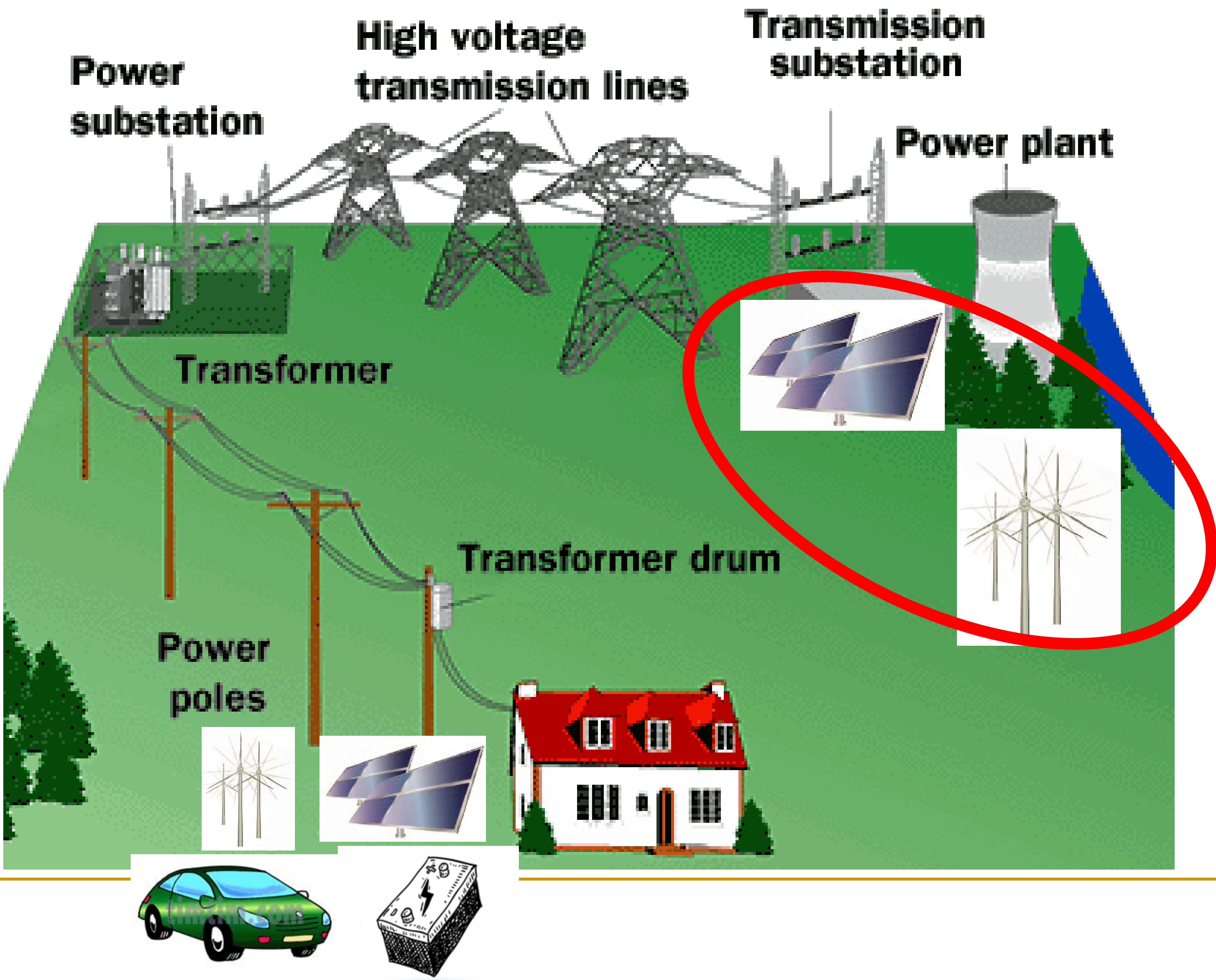
- Capacity target is administratively determined
  - Regulator determines the <u>generation capacity required</u> to meet a reliability target
- Consumers (LSEs) must all "buy" their share of this capacity
- Generators bid to provide this capacity
- Price paid depends on how much capacity is offered

Generators recover their fixed costs by

- Participating in the energy market as non-marginal generators
  - Paid in $/MWh at the energy market clearing price
- Participating in the capacity market
  - Paid in $/MW

New challenges

- Increased penetration of Variable Energy Resources (such as wind and solar)
  - Connected at transmission level
- Increased penetration of Distributed Energy Resources (DERs)
  - Resources connected to the distribution network


Power substation
High voltage transmission lines
Transmission substation
Power plant
Transformer
Transformer drum
Power poles

Balancing demand and supply becomes harder at all time scales!

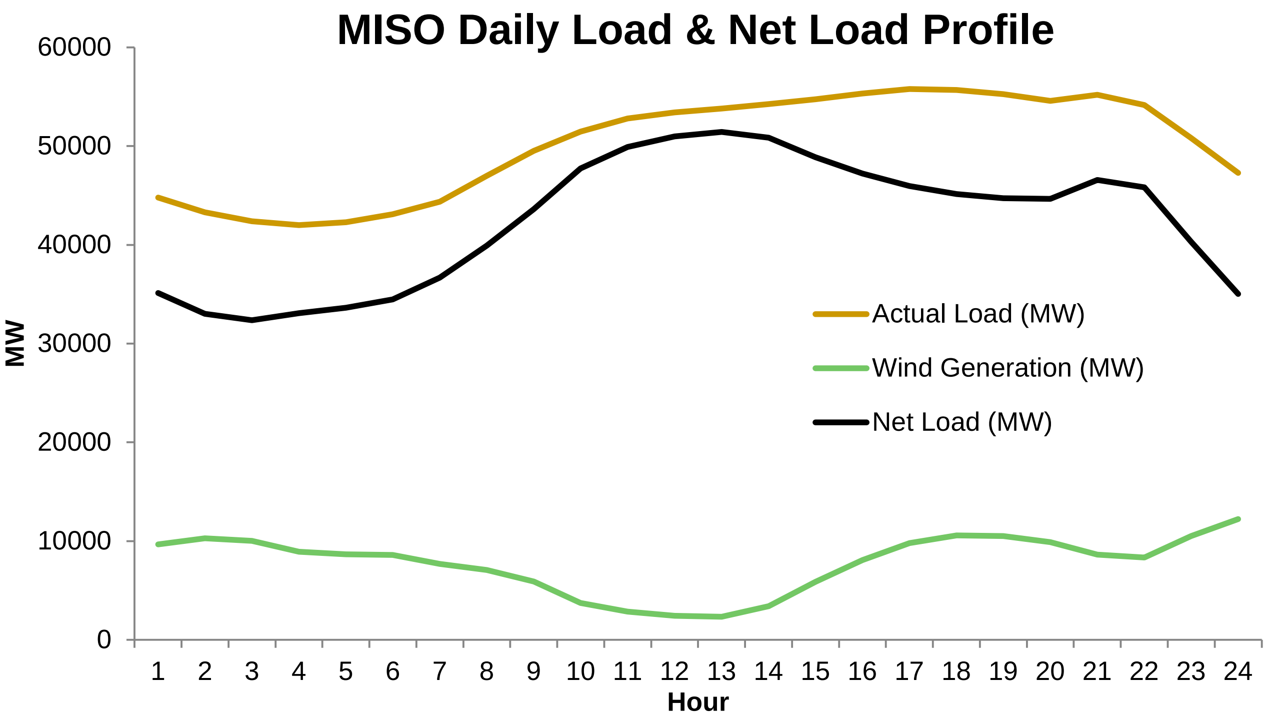
- Milliseconds to seconds
  - System dynamic stability studies
- Seconds to Minutes
  - Regulation
- Minutes to Hours
  - Load following
- Days, months, years
  - Capacity adequacy

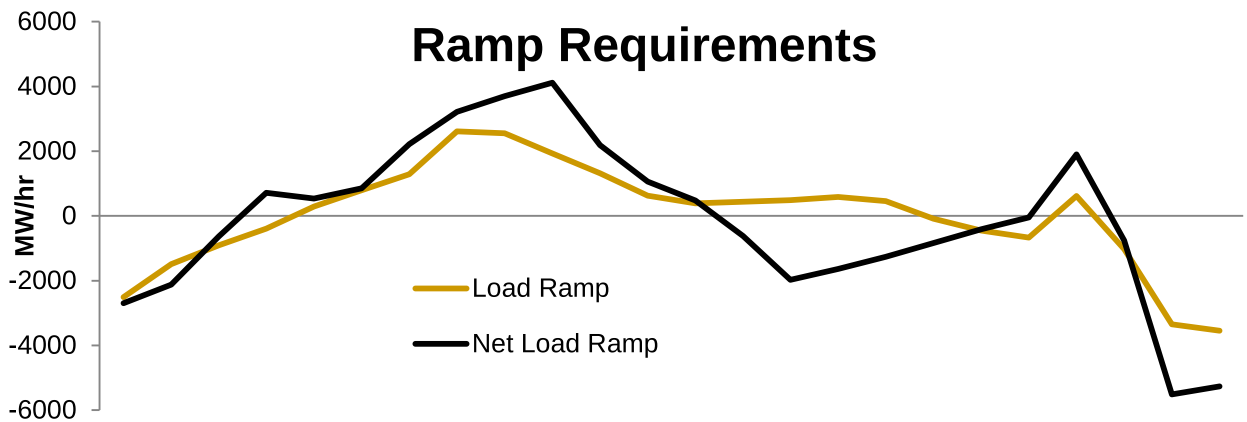
Geographic aggregation helps

New wind turbine technology and batteries help

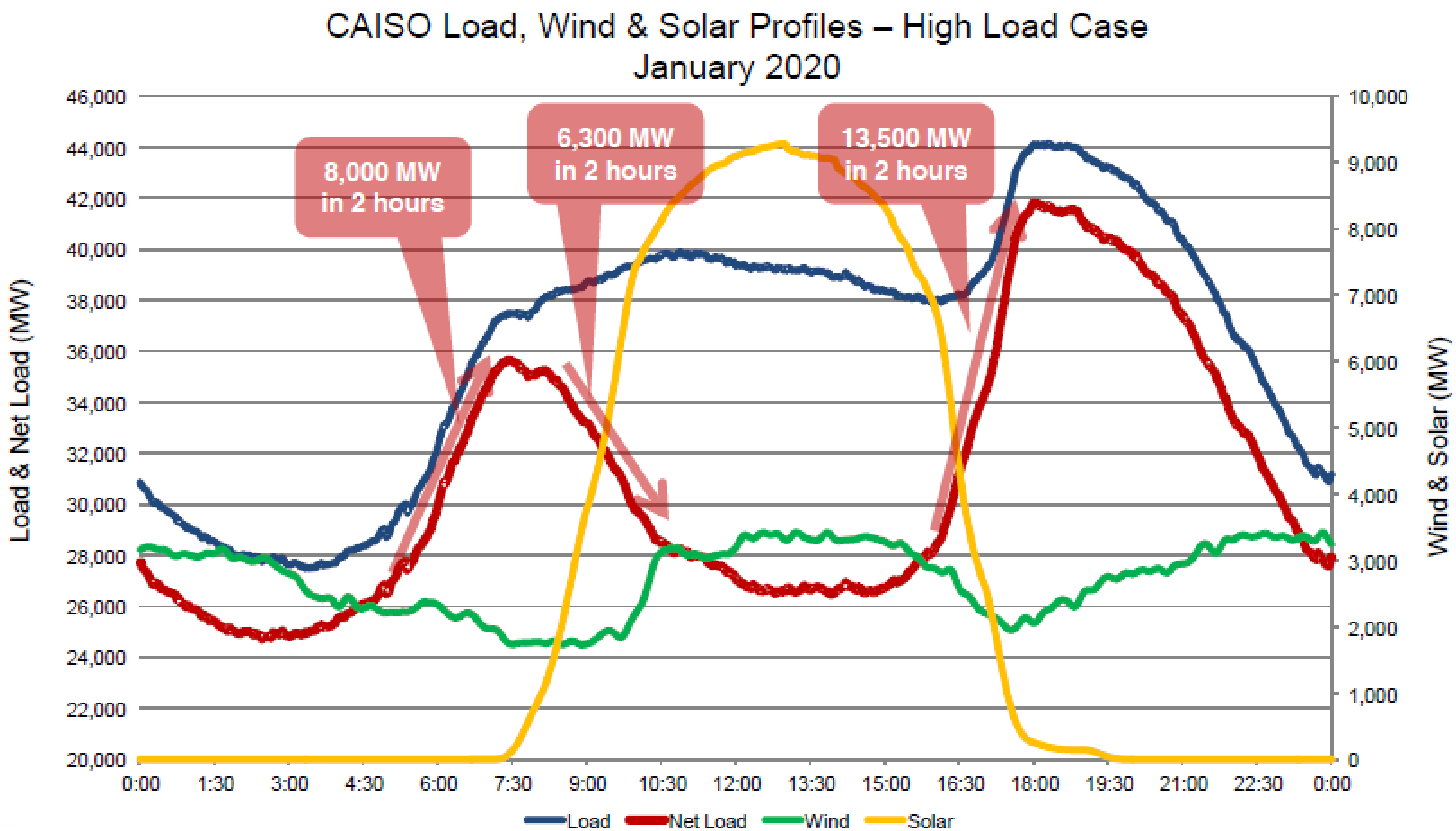
Implies higher costs and emissions

With wind balancing the system is harder





CAISO 2020: A lot of fast ramping conventional generation needed



Possible ways to deal with ramping shortages

- Increase the requirements for other ancilla
  - Commit more resources to provide fr
    - Use regulation resources to ramp **up** and ramp **down** a
  - Increase *spinning reserve* requirements
    - Use them to ramp **up**
- Use a *time-coupled multi-interval dispatch* r
  - I.e. implement a dispatch that "looks ahead"
- Modify Day Ahead UC-ED and Real Time E
  - explicitly ensure ramp capability is provisioned
  - to estimate the opportunity cost of ramp capability and compensate generators accordingly (Navid and Rosenwald, 2012,2013)

But increases costs because resources are paid twice !

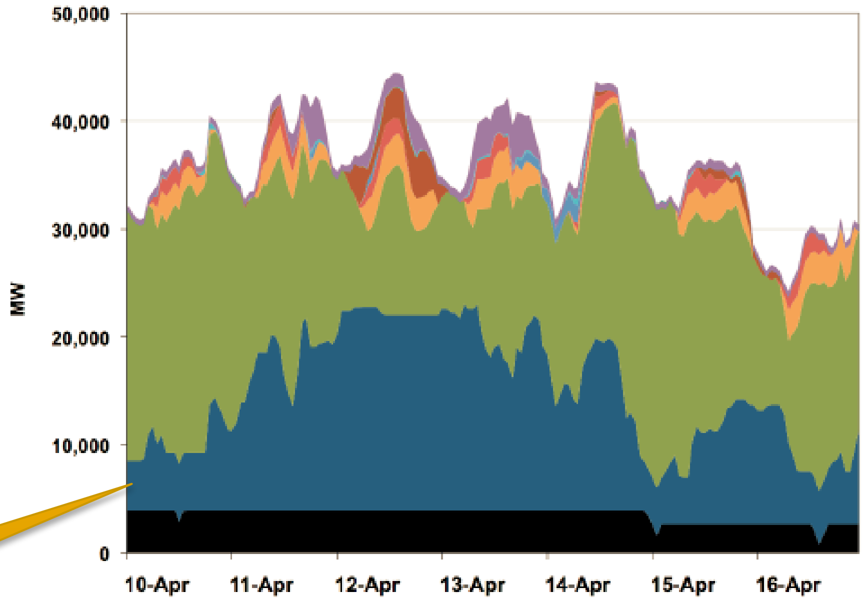
Will provide all the ramp needed with perfect forecast, but

1. Does not account for uncertainty
2. does not separate energy prices from ramp prices

Fossil-fired power plants will *cycle* more

2016: mid April

Future: 35% of wind



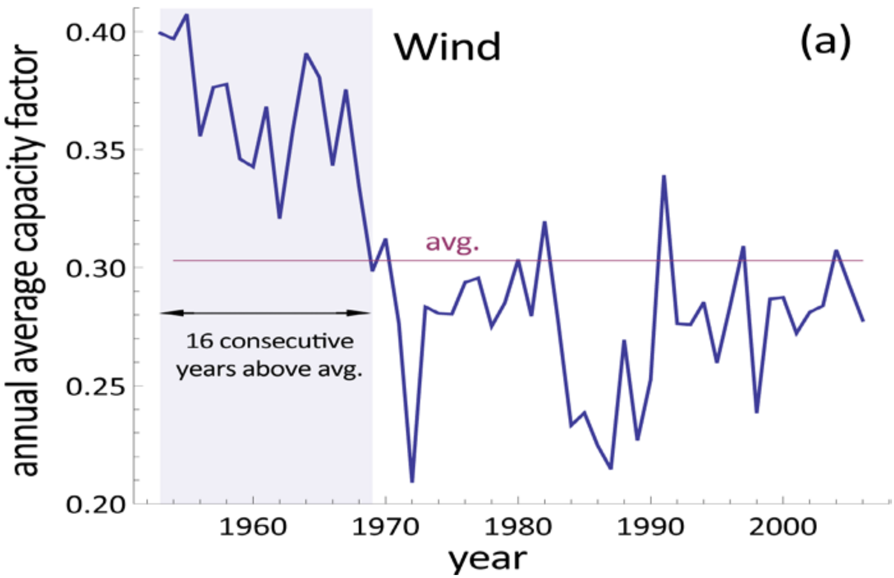
Coal plants will accelerate, shut-down and start-up more often than before

How will their emissions change?

Balancing demand and supply becomes harder at all time scales!

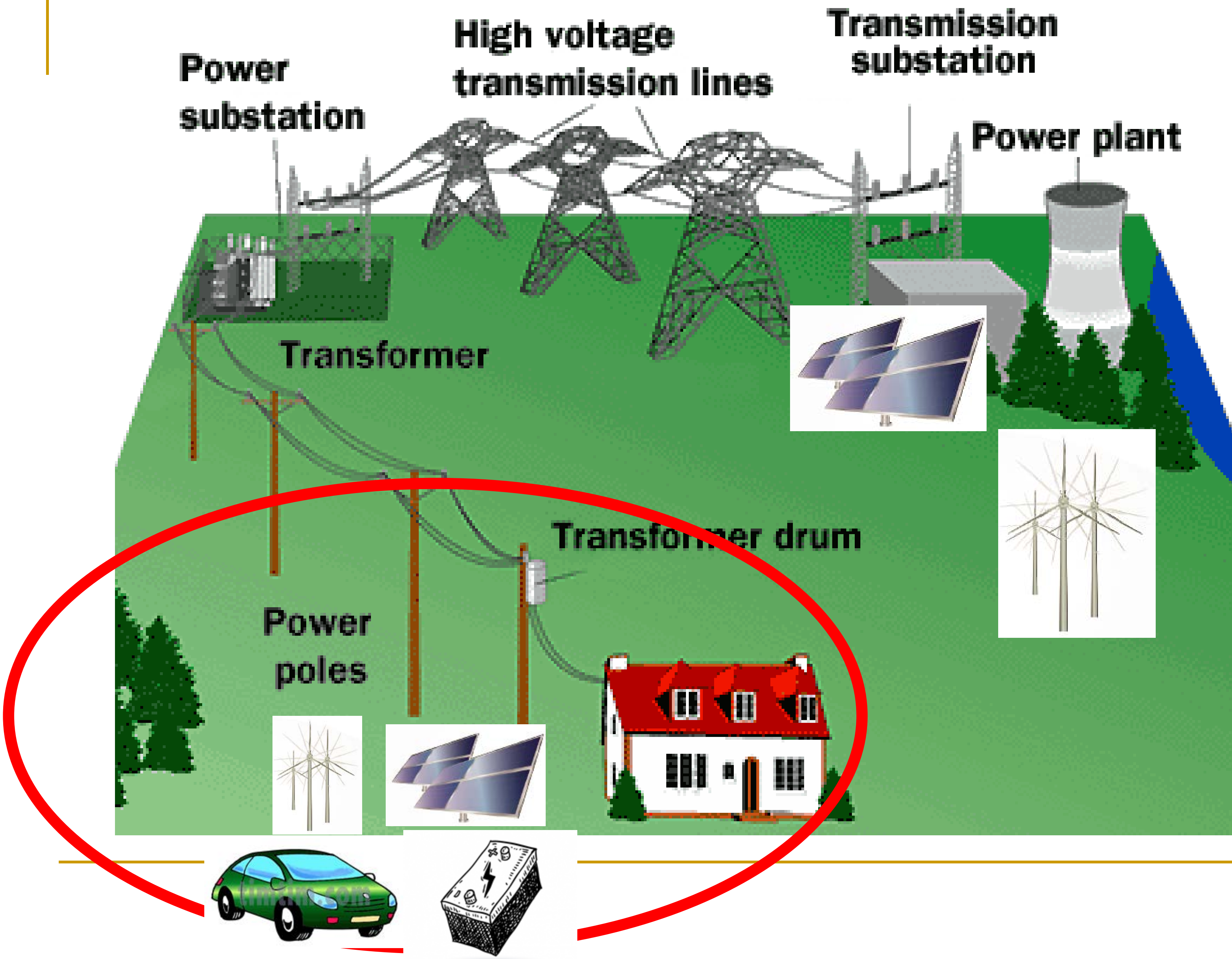
- Milliseconds to seconds
  - System dynamic stability studies
- Seconds to Minutes
  - Regulation
- Minutes to Hours
  - Load following
- Days, months, years
  - Capacity adequacy

long term variability



New challenges

- Increased penetration of Variable Energy Resources (such as wind and solar)
  - Connected at transmission level
- Increased penetration of Distributed Energy Resources (DERs)
  - Resources connected to the distribution network
    - Gas-fired generation
    - Solar PV
    - Small an mid size wind
    - Electric vehicles
    - Energy storage
    - Demand-side management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Proliferation of DERs implies the end of today's power system paradigm

- No more exclusive power flow from central generators to distribution systems
  - Large supply can be generated at the distribution level
    - And if not consumed locally will need to find its way to other markets through the transmission network

Proliferation of DERs implies the end of today's power system paradigm

- Need to reconsider today's distinction between transmission and distribution levels
  - Physical
  - Organizational
  - Regulatory / economic

- What will be the roles of the operators of the transmission system (ISO/TSO) and the operators of the distribution system (DSO)?
- How will DSOs be regulated?

Proliferation of DERs implies the end of today's power system paradigm

- There will be a multitude of agents,
  - consuming,
  - generating,
  - storing
  - and trading electricity
- How to ensure an efficient economic outcome?

by instituting a system that provides the right economic signals throughout the entire grid

Economic signals to ensure efficiency with DERs should:

- Value each service provided by a DER and a central generator
  - At the place it is provided
  - At the time it is provided

- Account for the effects of DER and central oeprators
  - on network thermal losses
  - on grid's technical constraints

- Allowing DERs to compete and collaborate in the provision of services

Services: all need to be priced to allow peaceful co-existence of DERs and the central grid

- Energy
  - Generation Capacity
  - Load following
  - Frequency reg
  - Black-start
  - Reserves
- Network
  - Transmission capacity
  - Voltage control
  - Reduction of thermal losses
  - Reduction of network constraints

Paradigm shift to allow DER market participation and reap its benefits

Today's markets

- Almost all costumers pay a flat rate
  - No locational variation
  - No temporal variation
  - No customer response!

Lots of opportunities to do this right!!

The future

- DSOs clear markets
  - Distributed LMPs are charged/paid to all end-nodes
  - Automated custumer's devices respond to DLMPs
- DSO coordinates with ISO

Thank you!

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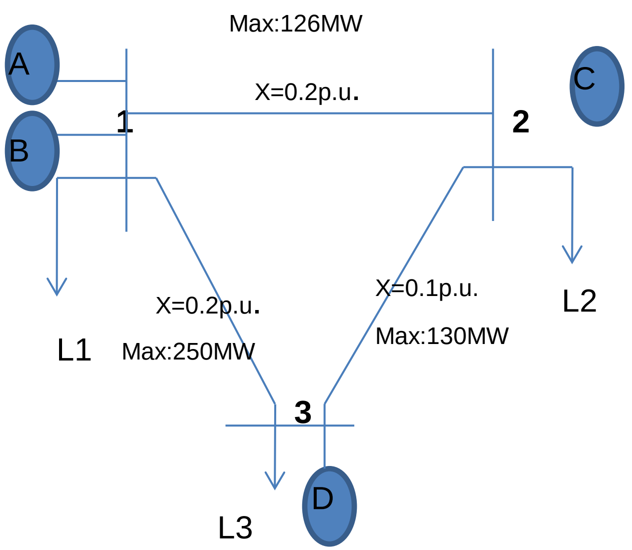
Security constrained economic dispatch – Linear Optimization model

- Decision variables
  - Generation of each unit $G_{A,}\ G_{B,}\ G_{C,}\ G_D$
  - Power flow on each line $f_{12,}\ f_{23,} f_{13}$
- Objective function
  - Minimize cost: $\min \sum_{i=1}^{N_G} C_i G_i$
- Constraints
  - Total Generation equals total load
  - Generation is within limits → for all generators
  - Power bus balance equation→ for all buses
  - KVL around the loop
  - Flows on lines do not exceed capacity →for each line

LMPs



Generator	Marginal Cost ($/MWh)	Maximum Generating Capacity (MW)
A	7.5	140
B	6	285
C	14	90
D	10	85

Imagine there is a total load of 410MW:
L1 = 50MW
L2 =60MW
L3 = 300MW

Unconstrained dispatch:
-Generate 285MW from B
-Generate 125MW from A

Price: $7.5/MWh at all nodes

But this is infeasible:
results in power flows that exceed the capacity of the lines

Market components (PJM)

- Energy Market
  - Day-ahead balancing market
  - Intra-day adjustments
  - Real-Time balancing market
  - Bilateral and forward markets
  - Self supply
- Ancillary services markets
  - Regulation markets: match generation with very-short term changes in demand via ACG
  - Primary reserves and secondary reserves: Take care of longer term imbalances between demand and supply
  - Black-start service
- Capacity Market
  - Assure long-term balancing between supply and demand
- FTRs market
  - To manage transmission congestion