



## ESIG Webcast Series

# Electricity Market Design Evolution under Large Loads

Balancing Large Load Growth with the Reliability and Efficiency of  
the Power Grid and the Operation of the Wholesale Market

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# AGENDA

## 1. Introduction and Motivation

Why are we looking at large loads and markets?

## 2. Large Load Participation Options

The ideal model for LL market participation

## 3. Grid impacts and allocation of costs for large load configuration

How do different co-location configs impact different grid services?

## 4. Capacity market design

Are flexible LLs buying capacity or selling it?

## 5. Balancing and Ancillary Services

What new grid services do LLs drive need for?

# Large Loads and Electricity Markets

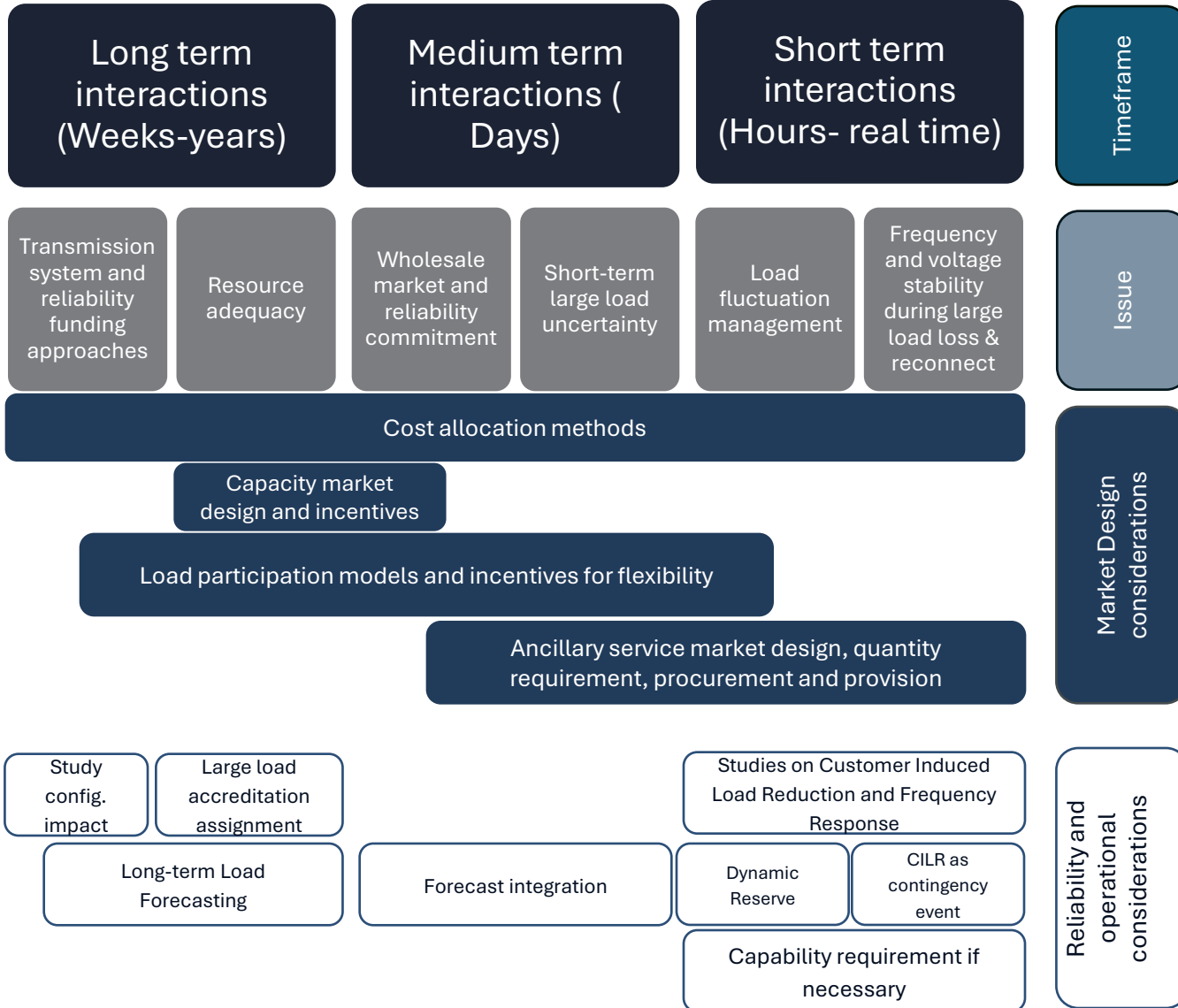
## Reliability

- Resource adequacy
- Customer Induced Load Reduction and loss of load contingency, frequency control
- Need for flexibility and potential impact on balancing reserve
- Short-term forecast uncertainty
- Price sensitivity uncertainty

## Economics

- Potential to raise prices (wholesale energy, capacity, and retail)
- Complex allocation of socialized wholesale costs due to load netting
- Interconnection speed incentive exceeding price incentives
- Market designs may not fully allow for large load flexibility

# Large load integration



## Collaborative Process

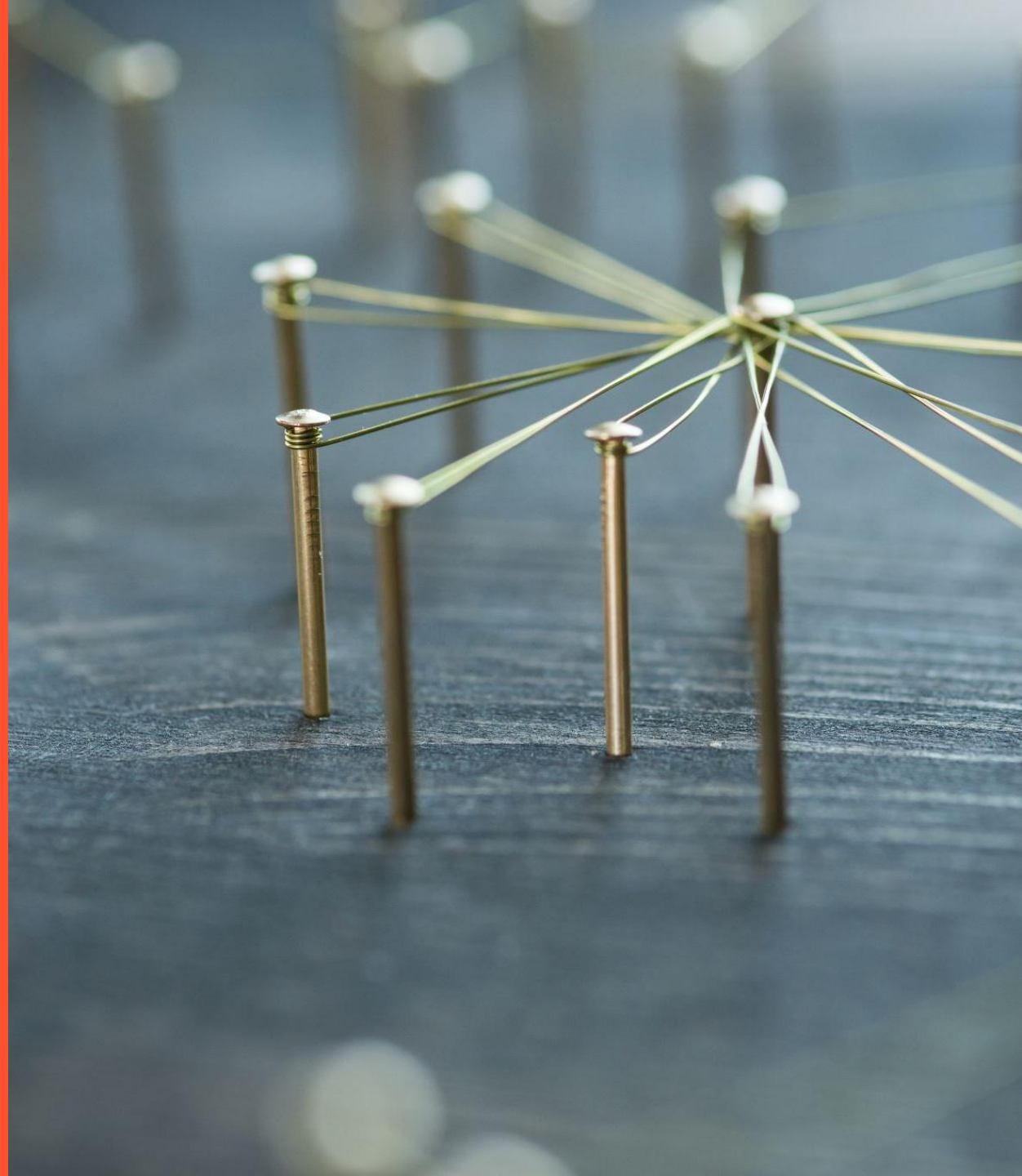
- Task Force consisting of 50+ participants
  - All N.A. ISOs
  - Utilities
  - IPPs
  - Hyperscalers
  - European and Australian participants
- Task Force Calls
  - 6 topical calls over the last 12 months
  - In-person workshop on flexibility
  - Expert panel on topic followed by breakout groups discussion
- **20 Recommendations across four topical areas**
- Collaborative report
  - Contributed writing
  - Redlined edits
  - Recommendation ranking
  - Verbal feedback

# Large Load Participation Models

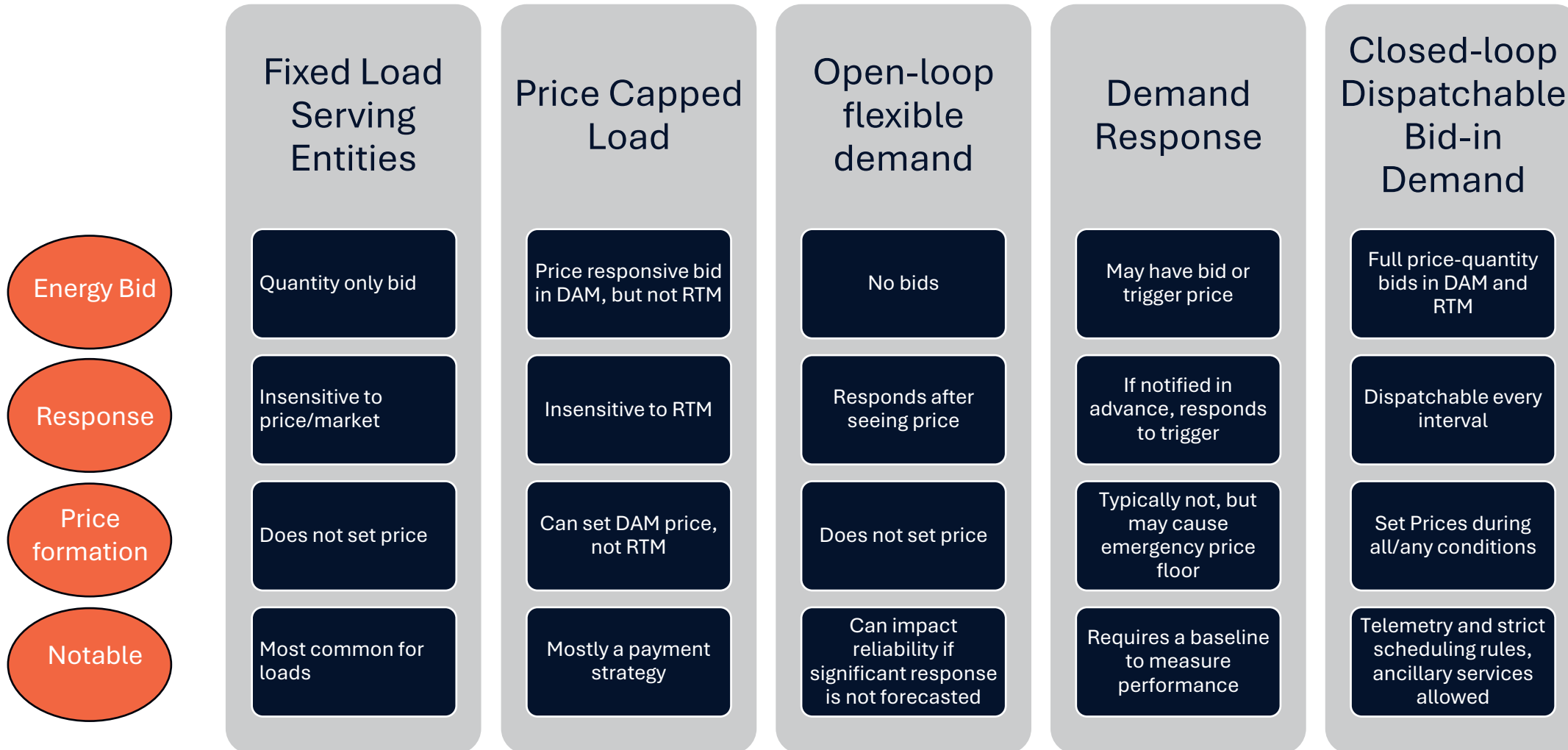
What load participation models exist?

What is the difference of open-loop and closed loop participation?

How do LL forecasts get integrated into markets?



# Demand Participation in Wholesale Electricity Markets



Will large loads utilize existing participation options or require new designs?

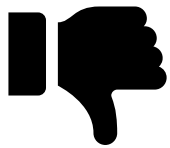
# “Flexibility without coordination may be worse than no flexibility”



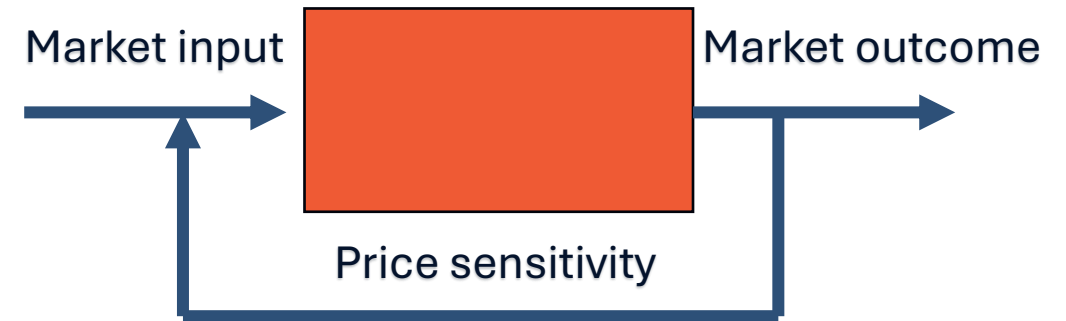
## Price Chasing



No telemetry, penalties, and simple strategy



Power imbalance, inefficient price outcomes



## Bid-in Dispatchable Demand

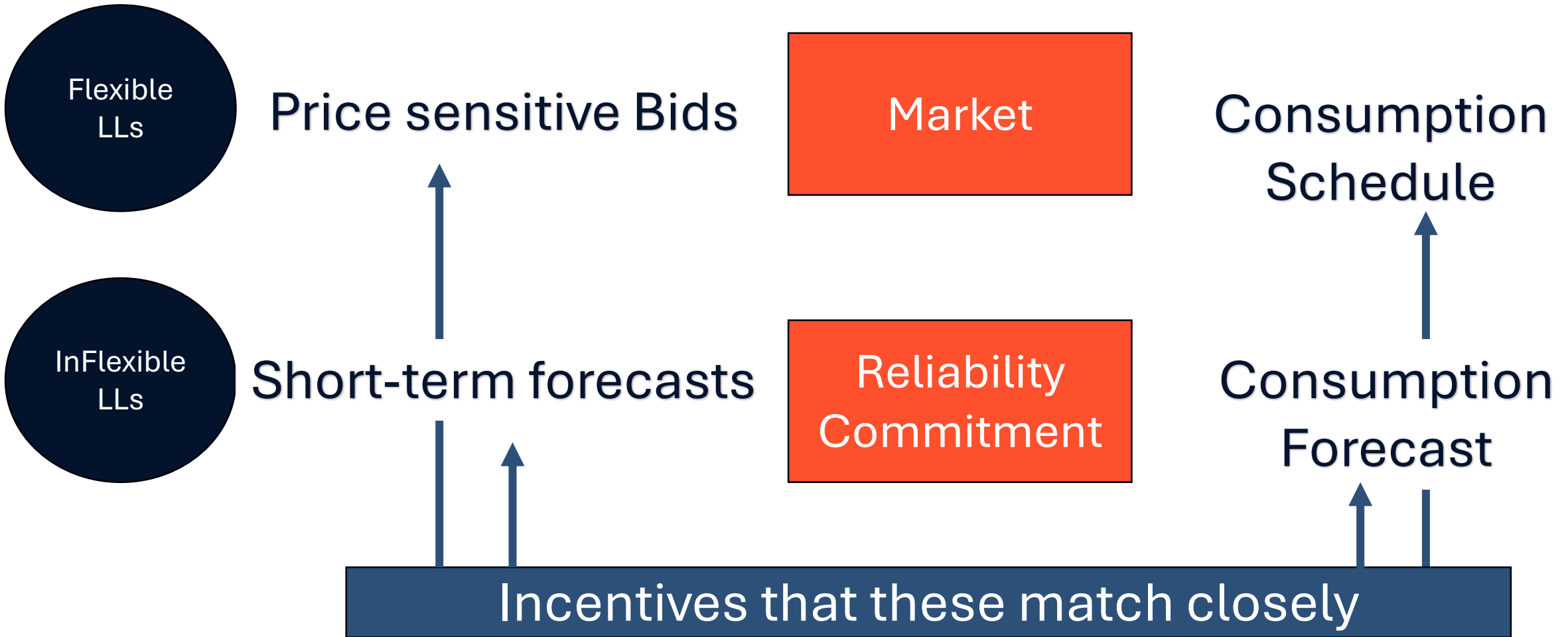


Efficient price formation, accurate dispatch,



Additional burden on participating loads

# Getting Consumption Accurate is Key



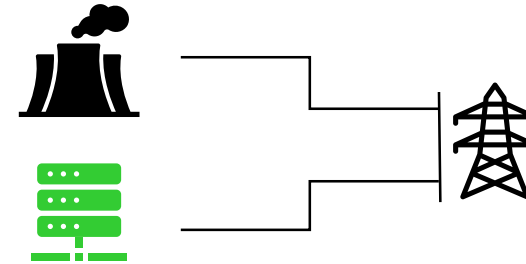
# Large Load Configurations

What configurations may exist?

How do configurations impact grid services?

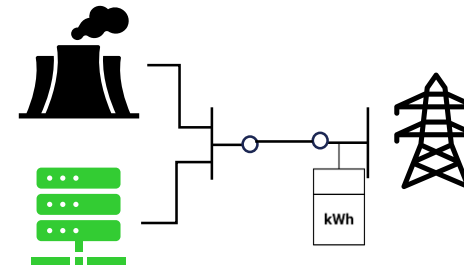
Efficient and fair cost allocation principles?

## Individually Metered LL and Supply



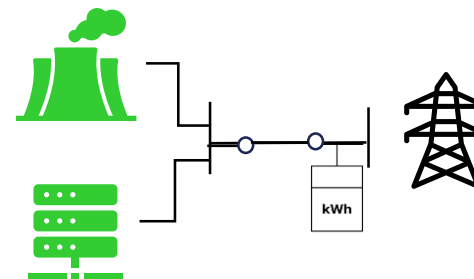
Large Load connects to the **grid**, separate from contracted generation

## Co-located LL BTM, able to disconnect



Large Load co-locates with **existing** generator, **behind-the-meter**, can isolate

## Co-located LL BTM. BYOC



Large Load co-locates with **new generation** it brings along

# Allocating Costs commensurate with grid impact

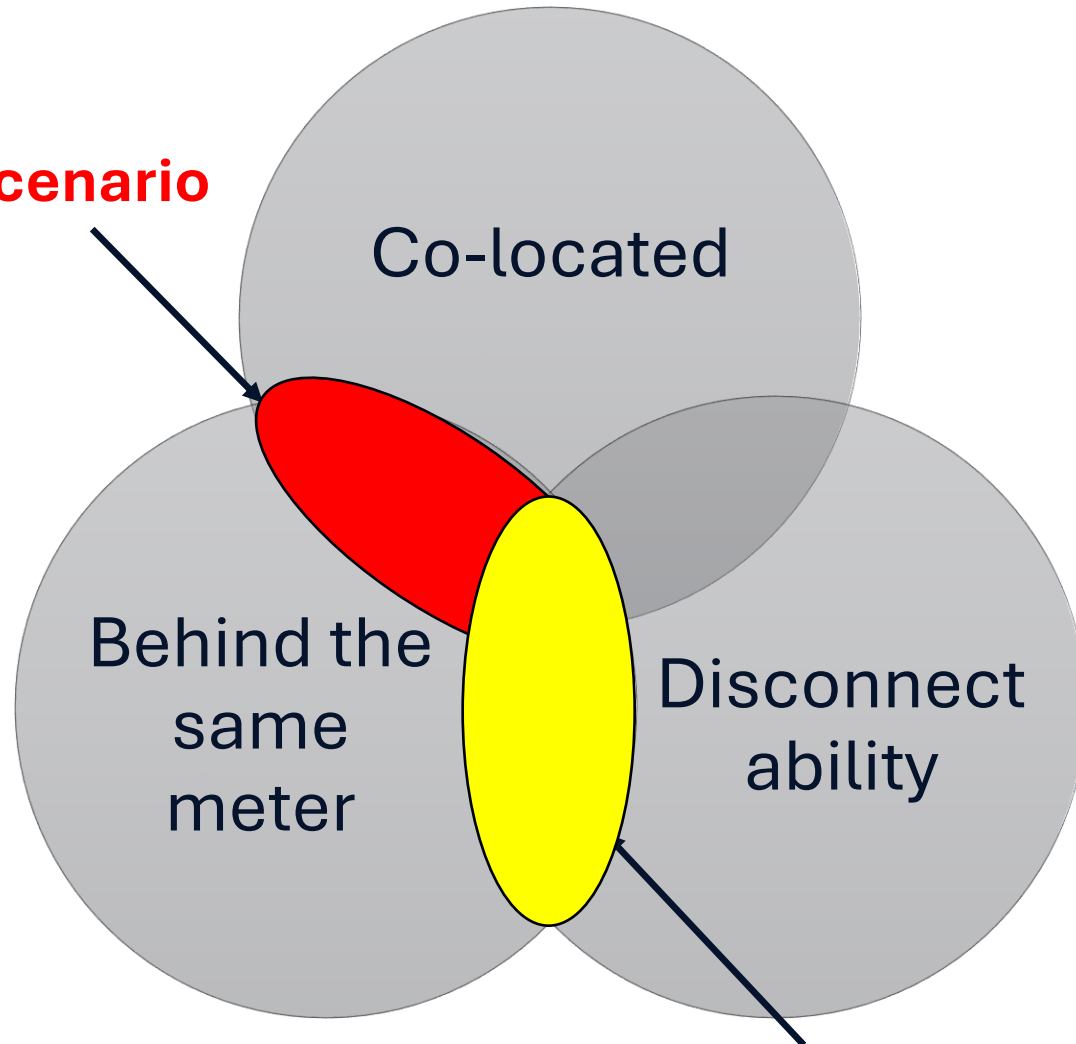
Determine all characteristics of the configuration, including parameters relevant to the power system and all components of the configuration

Assess the impacts of the configuration on various grid needs and services, while recognizing the cost of those needs and services

Allocate costs of those grid needs and services based on impacts while minimizing complexity and unintended consequences.

# What makes up a Large Load configuration

**Challenging scenario**



**Impact Uncertain**

Location

Metering and Telemetry

Disconnect ability

Supply resource

BYOC; TAEC

Net effect (supply, withdraw)

Flexibility

BYOC: Bring Your Own Capacity

TAEC: Take Away Existing Capacity

# The impact on the grid depends on configuration

Not necessarily the withdrawal amount

Service	Standalone	Co-located BTM (same meter)	Co-located BTM able to disconnect	Co-located BTM, and flexible consumption
Transmission				
ISO Services				
FERC & Regulatory Fees				
Capacity				
Frequency Regulation / Flexibility				
Spinning & Non-Spinning Reserve				
Voltage Support / Reactive Power				
Black Start				
Make-Whole Payment Uplift				

# Cost Allocation Methods for Socialized Wholesale Costs

	Most common method	Other notable methods
<b>Transmission</b>	Load ratio share through energy consumed by load serving entities, but separated by regional high voltage projects (allocated across system), local projects (allocated to local LSEs), and generator interconnection projects (allocated to the generator interconnecting).	ERCOT uses the consumption of LSEs over four coincident peak load hours across the summer months for allocation. SPP blends zonal and regional allocation for transmission projects between 100 kV and 300 kV.
<b>ISO Fee (e.g., Rate Schedule 1)</b>	Load ratio share through energy consumed by load serving entities.	NYISO charges overall costs through a ratio of 72% to loads and 28% to generators, with separate allocation to non-physical entities.
<b>Regulatory recovery (eg NERC, FERC)</b>	Load ratio share through energy consumed by load serving entities.	For FERC Fees, NYISO allocates 6% to non-physical entities, the remaining to the physical entities described for rate schedule 1.
<b>Frequency Regulation</b>	Load ratio share through energy consumed by load serving entities.	While regulation is typically allocated to loads, many ISOs also have penalties associated with poor scheduling performance which uses the regulation price as a penalty and can offset the total regulation cost allocated to loads.
<b>Blackstart Service</b>	Load ratio share through energy consumed by load serving entities.	PJM uses daily peak load contribution rather than the allocation being based on MWH. SPP does not allocate black start costs.
<b>Voltage Support and Reactive Power</b>	Load ratio share through energy consumed by load serving entities. but may allocate zonal costs to loads within a zone given the clearly local need for voltage and reactive power.	Some ISOs do not allocate costs for fixed support and all jurisdictional ISOs will eliminate due to FERC Order 904. PJM uses a peak load determinant instead of energy based.
<b>Make whole payments</b>	Make whole payment allocation may differ based on the type of payment but is typically allocated through load ratio share of total energy consumed by demand.	Some regions allocate costs to generators that have deviations in schedule which can also include virtual transactions.

# Capacity Market Design with Large Loads

Proposals to accommodate large load configurations

Proposals to accommodate large load flexibility

Accrediting large loads

Allowing buyer flexibility



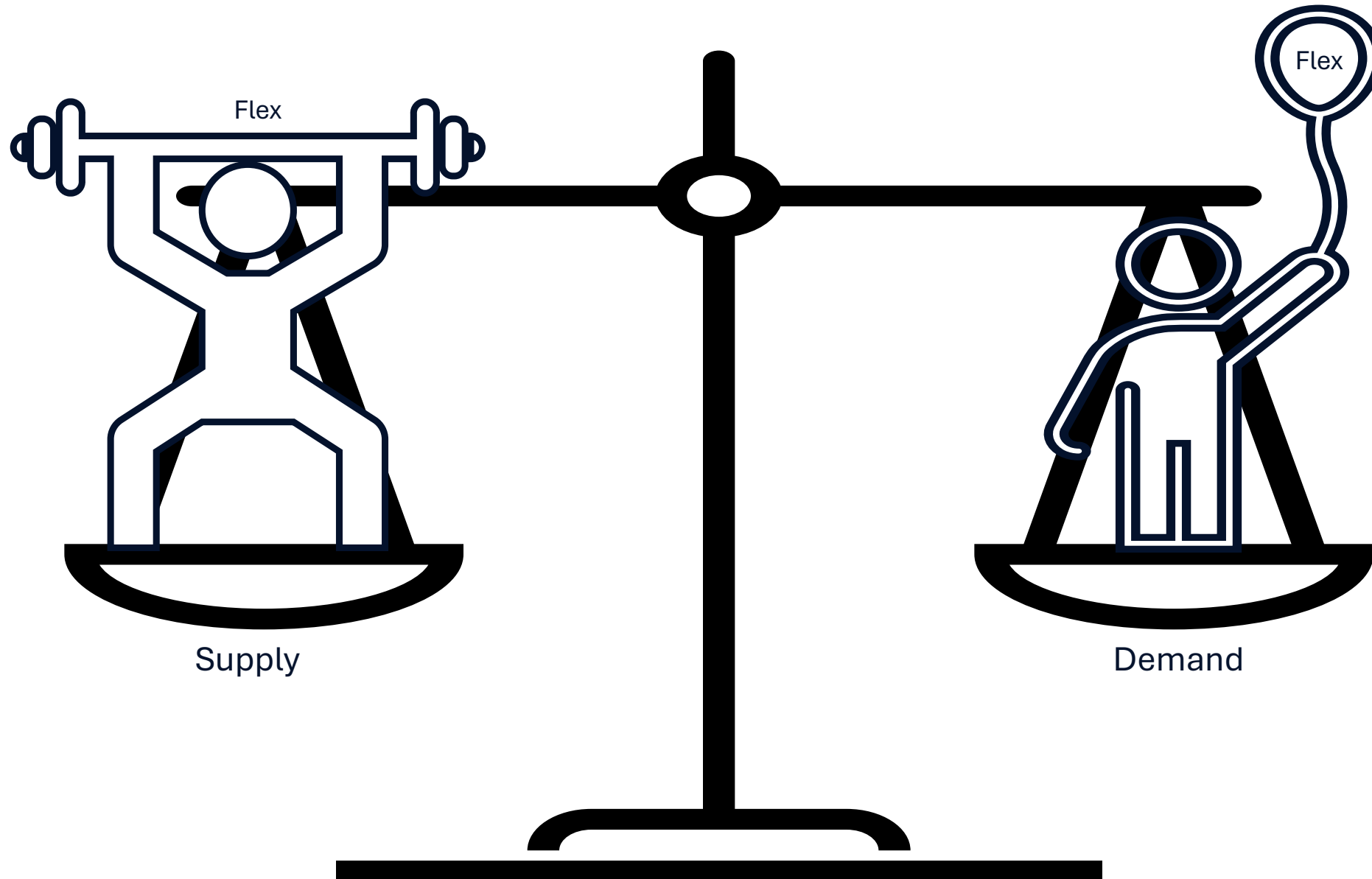
# Capacity Market Options

- **Supply-Backed Load**
  - “BYONC”
- Load brings equivalent capacity and avoids capacity market participation
- Similar to “Opt Out” (FRR, RBDC Opt out), but could be simpler
- **Non-capacity backed load**
  - “Connect and Manage”
- Loads agree to be curtailable during emergencies for speed and without capacity obligation
- Can be thought of as “willing to accept the reliability of the energy market”
- **Existing capacity linked load**
  - “Take Away Existing Capacity, TAEC”
- Loads contract with existing generation to speed interconnection
- Existing deactivation process, including system support (RMR), that may include adequacy, may be required

# If flexible large loads participate on the supply-side of the capacity auctions...

- Use state-of-the art accreditation methods as is used for other resources
- Represent parameters that reflect flexibility in their contribution determination (e.g., call, duration limits)
- If large loads exhibit unique characteristics, consider a separate accreditation class, or even multiple classes if sample size and accuracy benefit justifies complexity
- Consider appropriate treatment of must-offer obligation, capacity testing requirements, and performance penalties commensurate with other capacity resources
- Avoid double counting of flexibility in load forecasts when large flexible loads are on the supply side

# What side of the equation does flexible demand sit?



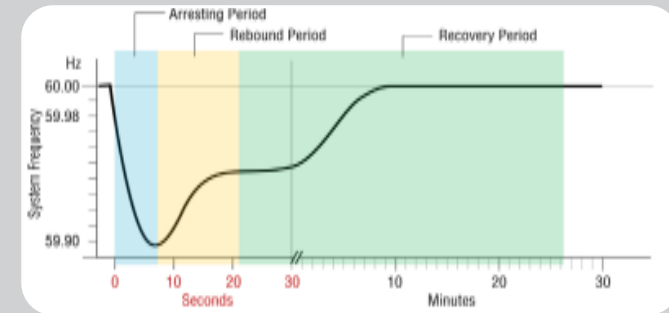
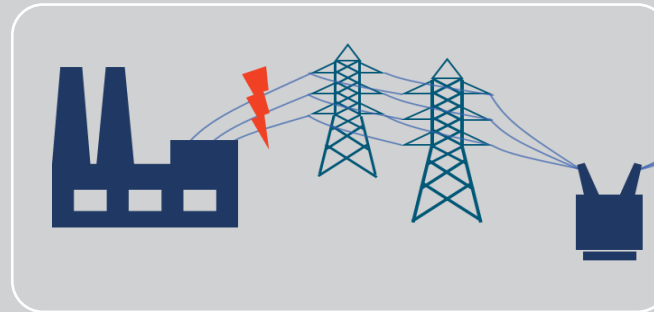
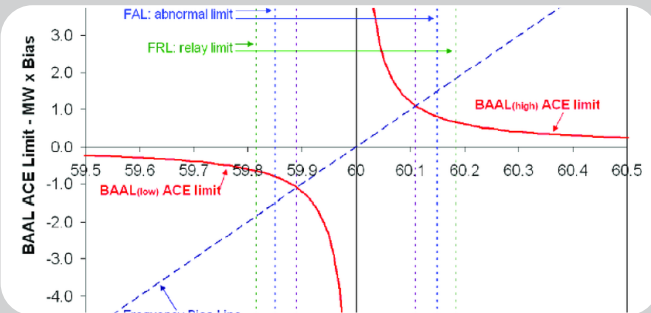
# Large Loads with Ancillary Services and Balancing Operations

Large load impact on reliability standards  
Contingency reserve and frequency control  
Capability and Utilization

Frequency rises to 60.047



# Large Loads on Standards and Reserve



## BAL-001 Control Performance

- Do the Balancing Area ACE Limit work for over-frequency?
- Are BAs prepared for regulation needs from added volatility?

## BAL-002 Disturbance Control Standard - Contingencies

- Should there be reference to MSSC for both supply loss and demand loss?
- Do the timing requirements for contingency event recovery and restoration period align for load loss events?
- What load loss events are reportable?

## BAL-003 Frequency Response

- Should over-frequency events be explicitly called out for measuring frequency response measure
- Should the IFRO be adjusted to account for over-frequency, or should there be separate IFRO for under- and over-frequency events?
- How are max delta frequency and “load loss protection criteria” determined?

# Frequency control during load contingency

- Waiting on figure from karin

# International Experiences

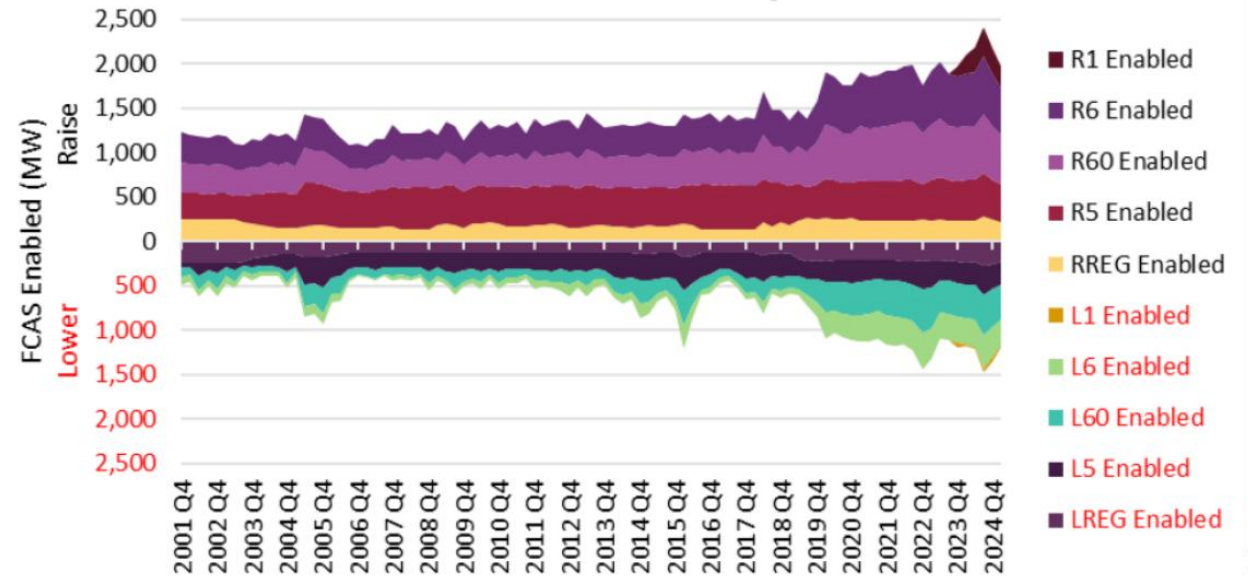


## Reference incident for loss of power consumption

Consider a reference incident equal to the maximum instantaneous loss of active power consumption due to the tripping of one or two connection points (also determined separately for the positive and negative directions)



## Lower frequency control ancillary service market products



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# What is next?

If we can think of large loads as the mirror image of large generators, the potential designs and strategies that accommodate these facilities will start to fall into place.

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**Thank you**

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The background of the slide is a dark blue, low-angle photograph of a high-voltage power line tower. The tower's complex lattice structure is silhouetted against the sky. A worker is visible in a bucket on the left side of the tower, and another worker is partially visible on the right. The overall scene is industrial and technical.

# Appendix Recommendations

# Recommendations: Market Participation

- **Recommendation 1:** Consider a flexible bid-in dispatchable demand participation model that can be used by large loads and allows participation in day-ahead and real-time energy markets, where demand entities submit price-quantity pairs that reflect willingness to consume at different price points. ERCOT's CLR model is an example, that other regions can review for possible adoption.
- **Recommendation 2:** Ensure that load flexibility assumptions considered as part of the process for preferential interconnection treatment are operationally enabled by market design and operating procedures. The specifics of how the load provides flexibility in operations may need to be explicitly defined as part of the rules prior to interconnection if any preferential treatment is given to the load for promising flexibility.
- **Recommendation 3:** Evaluate closed-loop models such as ERCOT's CLR to see which reasons for their limited adoption could be addressed, including which telemetry and other requirements are absolutely necessary and which could be relaxed.
- **Recommendation 4:** Consider discouraging price chasing for large loads of a certain size that do not put in price-sensitive bids. This could also be instituted through uninstructed deviation penalties or other incentives/disincentives for these large loads to instead participate using closed-loop, dispatchable bid-in demand models. However, any uninstructed deviation penalties should not be overly strict, so that participation in closed-loop models remains attractive for large loads.
- **Recommendation 5:** For large loads that are not participating through economic bids to consume, consider a requirement that a day-ahead, 24-hourly consumption forecast (i.e., self-scheduled consumption) is submitted for reliability purposes. Some regions may benefit from intra-day forecasts as well. There may need to be an incentive in place for providing accurate forecasts.

# Recommendations: Configuration

- **Recommendation 6:** Through studies and practical observation, determine which types of large load configurations impact each of the tariff-allocated grid services given characteristics of the configuration and the characteristics of the region and its existing services and cost allocation methods. Further, determine whether the use of back-up supply, curtailment flexibility, and different protection schemes that disconnect the large load from the grid during co-located supply faults or outages alter the impact on various grid services and needs.
- **Recommendation 7:** Evaluate cost allocation calculations for different grid services, fee recovery, and other wholesale costs. Methods that allocate costs commensurate with the way that entities are causing them are desirable, and allow for an incentive for these entities to reduce these costs. Discourage the ability to avoid such costs simply through reduced demand from netting. However, practicality, feasibility, and simplicity should be sought as part of any changes to these allocation methods.

# Recommendations: Capacity market design

- **Recommendation 8:** Allow large loads in BYOC configurations to utilize existing capacity market features allowing for the matching of specific demand with specific supply. This could include existing capacity market opt-out features such as fixed resource requirement or RBDC-opt-out or simpler options that account for bilateral capacity contracts between generation and load. Existing rules for these options should apply the same way including ensuring the accredited capacity of the BYOC generation truly covers the large load obligation including appropriate reserve margins applied.
- **Recommendation 9:** Determine whether generators that choose to leave the capacity market to dedicate themselves to a large load (TAEC) should follow existing generator retirement/deactivation rules to ensure reliability. ISOs, stakeholders, and state and federal regulators should consider whether resource adequacy and capacity shortfalls should be part of the evaluation performed during a deactivation and what steps are taken when capacity deficiencies are observed.
- **Recommendation 10:** If large load flexibility is treated as a supplier in the capacity markets, define accreditation rules for the capacity it can offer using state-of-the-art accreditation methods that are similar to the metrics used for other resources, and ensure accurate parameters are used in the probabilistic resource adequacy simulations used to determine capacity accreditation. Consider different accreditation classes for the capacity provided by large load flexibility, if different large load types are observed to provide different resource adequacy contributions from each other and from existing flexible load, ensuring that the sample size and accuracy benefits justify the added complexity.
- **Recommendation 11:** Ensure that load forecasts used in resource adequacy and capacity markets are aligned with any contributions from large loads that participate in capacity markets as capacity suppliers. Avoid double counting by ensuring the reduced load obligation is not already embedded in load forecasts that are used for the auction.
- **Recommendation 12:** In the longer term, explore the use of load flexibility bidding in price sensitivity on the demand side of the capacity auction as a possible way to replace the administrative demand curve. (This would be a greater departure from existing designs and may require significant study to determine its viability.)

# Recommendations: Ancillary Services and Balancing

- **Recommendation 13:** Encourage balancing authorities to study the sudden loss of very large loads on their systems to evaluate system response for meeting BAL-001, BAL-002, and BAL-003, or equivalent international balancing standards. For BAL-002 and BAL-003, consider whether CILR and over-frequency should be separately considered with requirements from loss of resource and under-frequency, respectively, or whether CILR events should be part of the events considered and/or driving requirements under those standards.
- **Recommendation 14:** For frequency response obligations and frequency response measurements, consider including CILR events that are similar in probability and credibility criteria to those used for loss of resources. However, keep in mind that the amount of frequency response in an interconnection or a balancing area can differ between under-frequency and over-frequency events. The obligation could utilize a maximum frequency threshold (similar to a minimum frequency threshold) for each interconnection that can help guide it and each balancing area to determine levels of frequency response during over-frequency conditions. A starting point could be a level below which generation protection settings would trip units offline.
- **Recommendation 15:** Consider introducing large load loss (or Customer induced load reduction) as a separate category of Most Severe Single Contingency (MSSC) that a balancing authority must evaluate along with its supply loss MSSC (MSSC-load). Regions should evaluate existing ride-through capabilities of emerging large loads to understand the resulting loss of a single CILR event, similar to the case for generation losses.
- **Recommendation 16:** Consider a downward contingency reserve service if MSSC-load studies lead to potential violations in standards. Use a similar quantification method to existing contingency reserve services. For example, the reserve could be set to be greater than or equal to the magnitude of the largest single CILR within the balancing area.
- **Recommendation 17:** Consider a downward contingency reserve market product in regions where ancillary service markets exist and where a downward contingency reserve service is determined to be advantageous to explicitly schedule and monitor. Prices should incentivize resources to hold downward capacity and reduce supply (or incentivize other loads to increase demand) during the CILR events to quickly restore the load loss. Supplemental reserve products that restore that reserve (analogous to traditional contingency reserve) could also be considered if studies show that their benefits outweigh the cost of market design and administration.
- **Recommendation 18:** Consider the inclusion of large load variability and uncertainty impacts at appropriate timescales for the determination of reserve requirements for non-event reserve services, such as using dynamic reserve methods. This can be done for reserve services such as regulation, flexibility and ramping reserve, as well as day-ahead uncertainty reserve products in the regions where they have been implemented.
- **Recommendation 19:** For any new requirements related to large loads, capability and utilization should be considered alongside each other but as separate decisions for requirements or incentives. Capability requirements for resources may be beneficial in some instances when capital costs are not significant and when they are performance-based and technology neutral, to allow for innovative capabilities. For most active power services, utilization (delivery) is best driven through ancillary service market incentives wherever markets are applicable.
- **Recommendation 20:** If large loads have the capability to provide any of the ancillary services mentioned, they should not be precluded from participating in ancillary service markets to provide those services.