Alternative RA Metrics, and RA Construct Elements

June 10, 2020

PRESENTED TO

MISO Resource Adequacy Subcommittee

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Agenda

- RA Metric Benchmark
- RA Construct Elements Benchmark

RA METRIC BENCHMARK

Resource Adequacy Metrics

Metric	Description	Pros	Cons	Examples
Loss-of-Load Probability (LOLP)	Probability of demand exceeding available resources at least once within a year. Units: % chance of >= 1 event per year	Easy to calculate and understand	Does not consider duration or size of an unserved load event	**Northwest Power and Conservation Council**: 5% LOLP
Loss-of-Load Events (LOLE)	Expected number of events per year in which demand is not served. One event in ten years translates to 0.1 LOLE per year. Units: Events per year	Easy to calculate and understand *Used by most U.S. systems*	Does not consider duration or size of an unserved load event	**Most U.S. Systems**: 1 loss-of-load event per decade or 0.1 event per year
Loss-of-Load Hours (LOLH)	Expected number of hours per year in which demand is not served. One day in ten years translates to 2.4 LOLH per year. Units: Hours per year	Considers the loss of load duration *Used by NERC*	Does not consider size of an unserved load event	**SPP**: 2.4 LOLH per year (equal to 1 day in 10 years)
Normalized Expected Unserved Energy (EUE)	Expected MWh of load that will not be served as a result of demand exceeding available supply. Can be normalized as % of load. Units: % of expected annual load	Considers both the duration and depth of supply shortages *Used by NERC*	Requires more sophisticated statistical methodologies	**Alberta**: Max annual EUE of 800 MWh **Australia NEM**: Max of 0.002% normalized EUE

Application of Resource Adequacy Metrics across RTOs

Under NERC Standard BAL-502-RF-03, MISO must calculate the planning reserve margin necessary to achieve 0.1 LOLE (but may have flexibility in how it sets requirements)

RTOs across the U.S. implement 0.1 LOLE differently

RTO	1-in-10 Standard Definition	Event Type
MISO	0.1 loss-of-load events per year	Firm load shed after all operating reserves and DR deployed
NYISO	0.1 loss-of-load events per year	Firm load shed after 10 min and 30 min operating reserves and voltage reduction deployed
ISO-NE	0.1 loss-of-load events per year	Firm load shed after voltage reduction and DR deployed, but 200 MW of operating reserves maintained
PJM	0.1 days with loss-of-load per year	Firm load shed after interruptible load and 30 min reserves deployed, but before voltage reduction or 10 min reserves deployed
SPP	2.4 loss-of-load hours per year	Not explicitly defined

Source: Pfeifenberger, et al., Resource Adequacy Requirements: Reliability and Economic Implications, Prepared for FERC, September 2013.

NERC Assessment of RA Metrics

In its 2016 assessment, NERC chose two metrics to represent a consistent measure across different areas:

Expected Unserved Energy (EUE)

- Measure of the system's capability to continuously serve all loads at all delivery points while satisfying all planning criteria
- Energy-centric and analyzes all hours of a particular year
- Summation of the expected number of MWh of load in a given year that will not be served as a result of demand exceeding available capacity

Loss of Load Hours (LOLH)

- The number of hours during a given time period where system demand will exceed generating capacity, which accounts for duration of events but not magnitude

NERC has included estimates of these two metrics in its reliability assessment reports since then

Source: NERC, Probabilistic Assessment Improvement Plan: Summary and Recommendations Report, December 2015. Available at: https://www.nerc.com/comm/PC/Reliability%20Assessment%20Subcommittee%20RAS%202013/ProbA%20%20Summary%20and%20Recommendations%20final%20Dec%2017.pdf

RA METRIC BENCHMARK

Tradeoffs of Resource Adequacy Metrics

Metric	Pros	Cons
Loss-of-Load Metrics (LOLE, LOLP, LOLH)	• Easy to calculate and understand • Widely used across U.S. RTOs • LOLH accounts for duration	• LOLE & LOLP do not account for duration or size of events • Reliability level changes with system size. Does not allow for direct comparison among jurisdictions • Measurement/interpretation are not aligned across markets • Has not been updated for changes in electricity industry
EUE Metric	• Measures both the duration and magnitude of load shed events due to inadequate supply • If normalized, reliability levels are not effected by growth in system size. Can also be used to compare across systems of different sizes. • Used by NERC in their assessments	• Not commonly used in U.S. RTOs • Would need to determine desired target level based on LOLE/EUE studies

We recommend that MISO consider adopting EUE if:

- The benefits of planning for a consistent level of load shed each year…
- Outweighs the challenges of switching away from LOLE

Agenda

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MISO Reliability Challenges

MISO is considering reforms to address three different types of shortages

Types of Shortages	Primary Analytical Tool	Is it a Resource Adequacy Issue?
Installed capacity insufficient to meet demand year-round	Hourly (8760) RA simulations	Yes, and the RA construct can account for sub-annual needs and capabilities (to inform investments)
Available capacity insufficient during shoulder months due to excess outages	Hourly (8760) RA simulations	Primarily an outage coordination issue, but can be informed by identified RA needs and have implications for resource accreditation
Committed capacity insufficient to meet real-time flexibility needs	DA-to-RT (DART) simulations	Primarily an operations and E&AS markets issue to better use installed capacity; add RA requirement only if insufficient installed flexible capacity

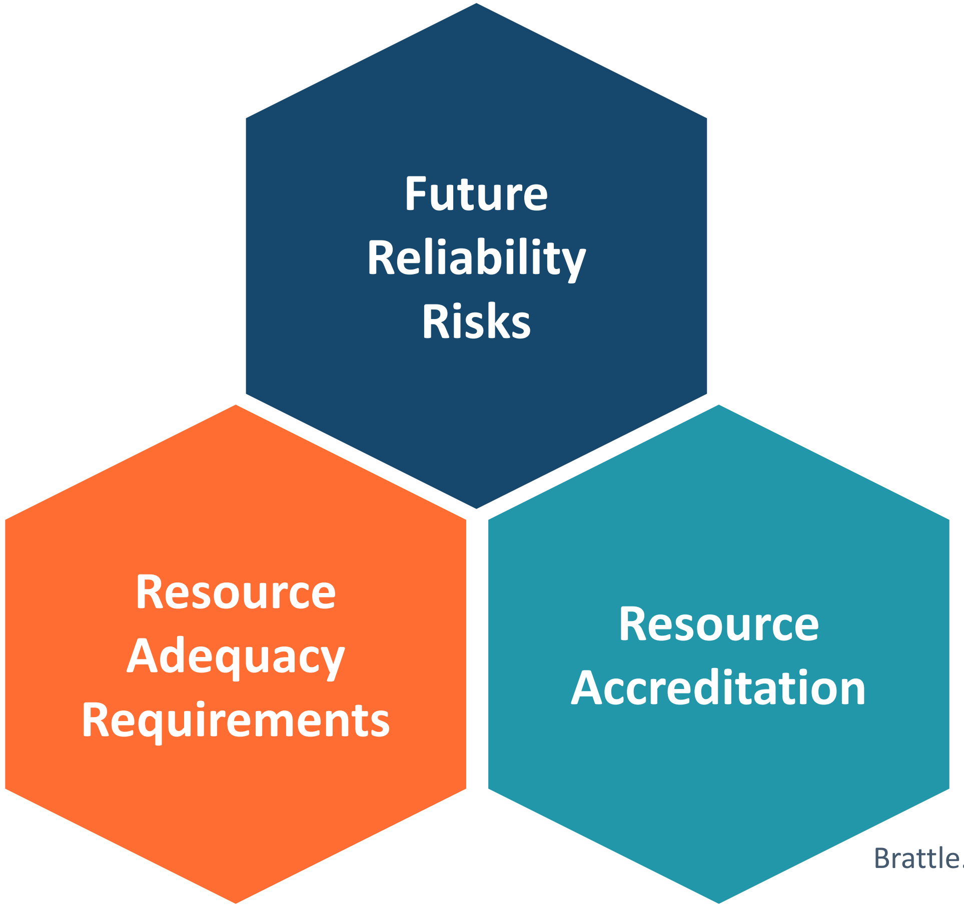
We primarily focus in these slides on the Resource Adequacy construct to ensure sufficient installed capacity in MISO

Resource Adequacy Construct Elements

MISO analyses of historical data suggest reliability risks are shifting away from just summer peak

So what is next? What are the key elements of its design to consider when evaluating potential changes to the MISO RA construct?

Key elements fall into three categories:



Future Reliability Risks

Future Reliability Risks

Tools What tools can assess future reliability risks?	• Primarily, SERVM and GE-MARS, combined with future scenarios
Patterns of Reliability Risks Are there times outside summer peak with reliability risks?	• Southern Company and TVA observe risks in the summer & winter • PJM and ISO-NE identified winter fuel security and availability risks • AESO identified tight “supply cushion” hours year-round, many in summer despite load being highest in winter
Metrics What are the right metrics to quantify those risks?	• Most U.S. system operators use LOLE • Alberta, Australia, European systems use EUE • NERC uses EUE and LOLH in its assessments

Note: Examples from Alberta and Ontario refer to their proposed market designs that have since been delayed or cancelled

Resource Adequacy Requirements

Requirement Periods Should there be multiple periods or a single annual period addressing year-round risks?	• ISO-NE, PJM, and Alberta set a single annual requirement address year-round risks • Ontario, Southern Company, and TVA set seasonal requirements • CAISO and NYISO set monthly requirements
System-Wide Requirement How to determine the system-wide or zonal requirement for each period?	• Most markets continue to set a RM based on peak load hours • Alberta proposed setting its RM based on tightest supply hours • Ontario proposed design considers the relative costs of reducing LOLE in each season for setting seasonal requirements
Local Requirements How to translate the system-wide or zonal requirement to each LSE?	• CPUC requires LSEs to meet the same 15% RM each month with separate local/zonal requirements • SPP requires its LREs to meet 12% RM during summer peak
Additional RA Requirements Are additional RA products needed?	• California added a Flexible RA (installed capacity) requirement

Note: Examples from Alberta and Ontario refer to their proposed market designs that have since been delayed or cancelled

Resource Accreditation

Basis for Accreditation How to determine resource availability during each requirement period? Should it account for planned outages?	• CPUC uses ELCC for both wind and solar; UCAP for rest • NYISO sets solar & wind values based on average output during peak load hours (*e.g.*, 2-6 pm in June – August for summer) • Alberta proposed UCAP as average output during 200 tightest supply-cushion hours, irrespective of planned or forced outages
Participation Requirements Will different requirements be allowed for different resources across periods? What obligations to place on resource availability during shortage events?	• PJM used to allow Summer DR (only available in the summer) • Ontario proposes to allow for Seasonal or Annual resources • CPUC and NYISO set monthly/seasonal values for solar and wind • Singapore proposes to allow daytime-only participation for DR
Penalties & Incentives How to assess performance and set penalties and incentives during events?	• Performance incentives/penalties assessed in ISO-NE and PJM based on availability during shortage events • Alberta proposed to assess based on shortage events and tight supply hours

Note: Examples from Alberta and Ontario refer to their proposed market designs that have since been delayed or cancelled

Industry Changes in Resource Adequacy Requirements

PRESENTED TO
MISO Resource Adequacy Subcommittee

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May 6, 2020

THE Brattle GROUP

Organized markets have continuously modified RA requirements since inception

…with increasing focus on a high-renewable future

BEFORE 2010 | 2010 | 2012 | 2014 | 2016 | 2018 | 2020

California
In 2004, required LSEs to meet monthly RA requirements

NYISO
In 1999, implemented seasonal capacity market

California
Initiated process to identify flexibility needs

ISO-NE
initiated process to improve reliability throughout the year

PJM
Initiated process to improve availability following Polar Vortex

ISO-NE
Implemented Pay for Performance (PFP) incentives and short-term Winter Reliability Program

California
Implemented Flexible RA requirements

PJM
Implemented Capacity Performance rules

Alberta
Proposed annual capacity market based on "lowest supply cushion" hours

Ontario
Proposed seasonal capacity market

NYISO
Launched "Grid in Transition" plan to update market design

California
Proposed Flexible RA changes to align with operational needs

ISO-NE
Developed "Energy Security Improvements" to increase fuel availability; stakeholders initiated "Transition to Future Grid" study

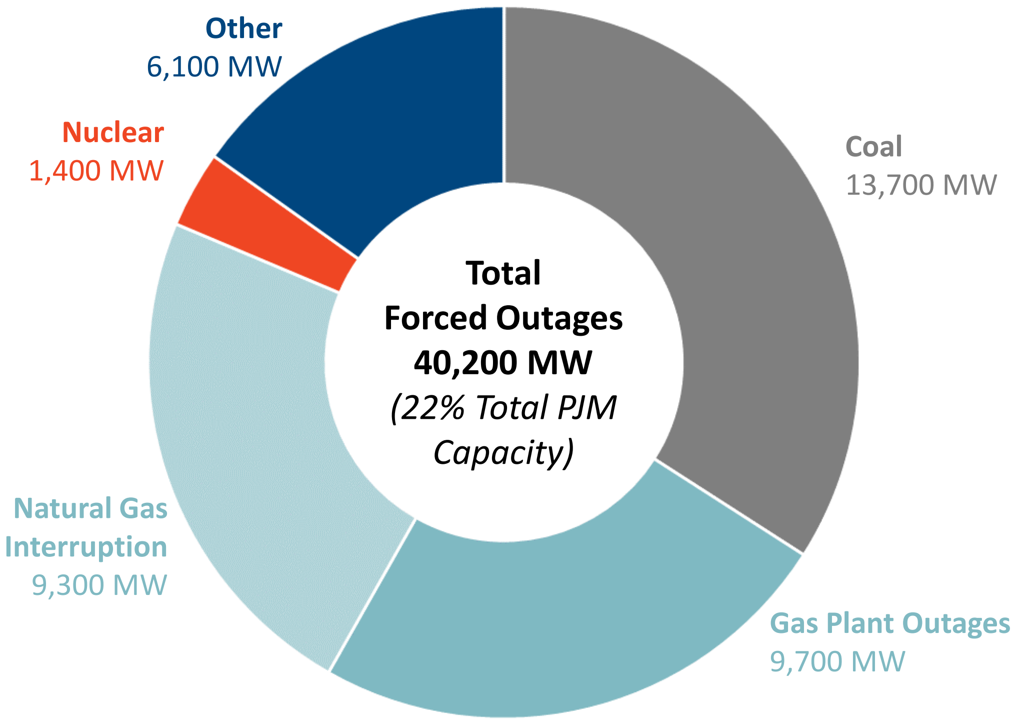
Other jurisdictions are addressing sub-annual RA needs

- The industry is reconsidering RA constructs given portfolio changes (and have in the past made changes to address seasonal availability, winter fuel assurance, and resource performance)
- There are various ways to address sub-annual RA based on regional needs and market/regulatory environment

Market	RA Period	Basis for Requirements	Basis for Resource Accreditation	Other Initiatives to Address Sub-Annual Needs
ISO-NE	Annual	Summer Peak	Year-round capability; seasonal resources have to pair with complements	Pay-for-Performance; Winter Reliability Program; Fuel Security Improvements; "Transition to Future Grid" study
PJM	Annual	Summer Peak	Year-round capability; seasonal resources have to pair with complements	Capacity Performance; Reserve Market enhancements
Alberta *(proposed)*	Annual	Tightest supply cushion hours	Tightest supply cushion hours	Identified 250 tightest supply cushion hours throughout the year
Ontario *(proposed)*	Summer & Winter	Summer & Winter Peaks	Seasonal Capability	Created additional operating reserves to address flexibility needs
Southern Co. & TVA	Summer & Winter	Summer & Winter Peaks	Seasonal Capability	Distinct summer and winter planning reserve margins
NYISO	Monthly and voluntary 6-month strips	Summer Peak	Seasonal Capability	Dual-fuel and minimum oil burn requirements; "Grid in Transition" study
CAISO	Monthly	Monthly Peaks	Monthly Capability	Flexible RA requirement; "Flexiramp" real-time product

PJM reformed following the Polar Vortex

Outages by Primary Fuel
7 pm, January 7, 2014



Source: "Analysis of Operational Events and Market Impacts During the January 2014 Cold Weather Events," PJM Interconnection, May 8, 2014

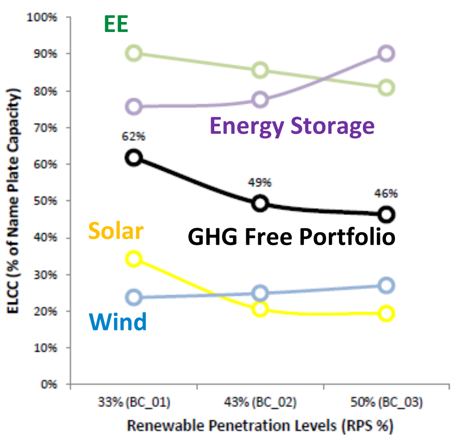
"Capacity Performance"

- Year-round capability required for "Annual Resources"
- $3500/MWh penalties during shortages (+LMP)

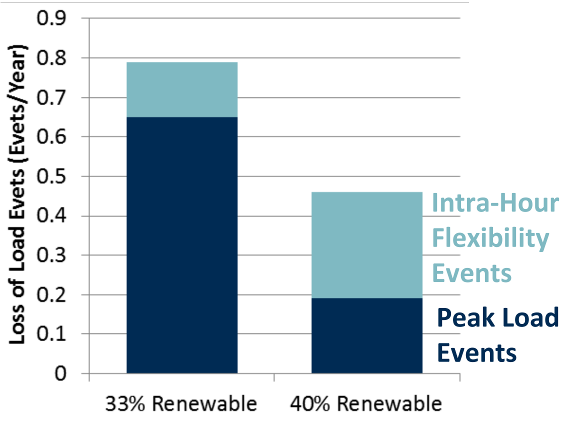
California implemented an annual and monthly RA requirement in 2004

- LSEs must meet 90% of their obligations a year-ahead and 100% a month-ahead
  - Allow LSEs flexibility to firm up remaining obligations based on updated load forecasts
- Resource accreditation revised as net peak shifted into evening hours (mostly after sunset), substantially reducing solar ELCC
- Reliability and hourly production cost simulation tool simulations show:
  - Resource availability during net peak is a good approximation of ELCC
  - As more renewables are added, shortage events will occur during ramping periods

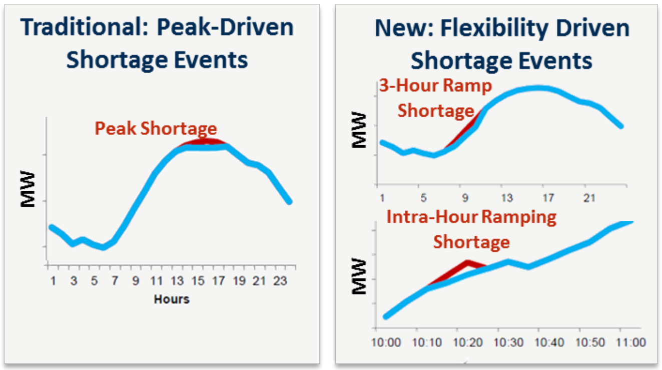
ELCC with Increasing RPS



California Reliability Events (2024)



Projected Types of Shortage Events

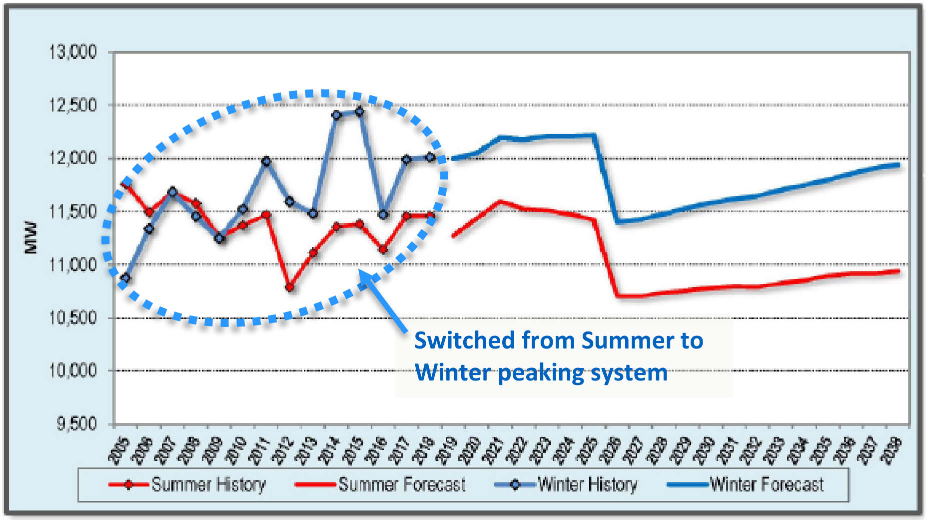


Sources: Astrape Consulting's Jan 6, 2016 and Aug 15, 2017 presentations to CPUC Flexibility Metrics and Standards workshops.

Southern Company and TVA implemented summer and winter planning reserve margins

- Winter (heating) peak loads have been growing in Southern's service area; Alabama Power shifted to winter peaking in 2011
- High weather-related peak load uncertainty and resource outages yield **25% winter PRM** for Alabama Power, compared to **15% summer PRM**
- TVA also uses summer and winter PRM but different approach based on **0.05 LOLE in each season**

Alabama Power Historical and Forecast Peak Load



Alabama Power Target Planning Reserve Margins

	Previous Reserve Margin Study	Updated Reserve Margin Study
System Long-Term Target Planning Reserve Margin (Summer)	16.25%	16.25%
System Short-Term Target Planning Reserve Margin (Summer)	14.75%	15.75%
Diversified Long-Term Target Planning Reserve Margin (Summer)	14.74%	14.89%
Diversified Short-Term Target Planning Reserve Margin (Summer)	13.26%	14.39%
System Long-Term Target Planning Reserve Margin (Winter)	-	26.00%
System Short-Term Target Planning Reserve Margin (Winter)	-	25.50%
Diversified Long-Term Target Planning Reserve Margin (Winter)	-	25.25%
Diversified Short-Term Target Planning Reserve Margin (Winter)	-	24.75%

Source: Alabama Power, "2019 Integrated Resource Plan Summary Report," 2019.

NYISO has a two-season RA construct and is looking to future needs

Seasonal resource adequacy construct

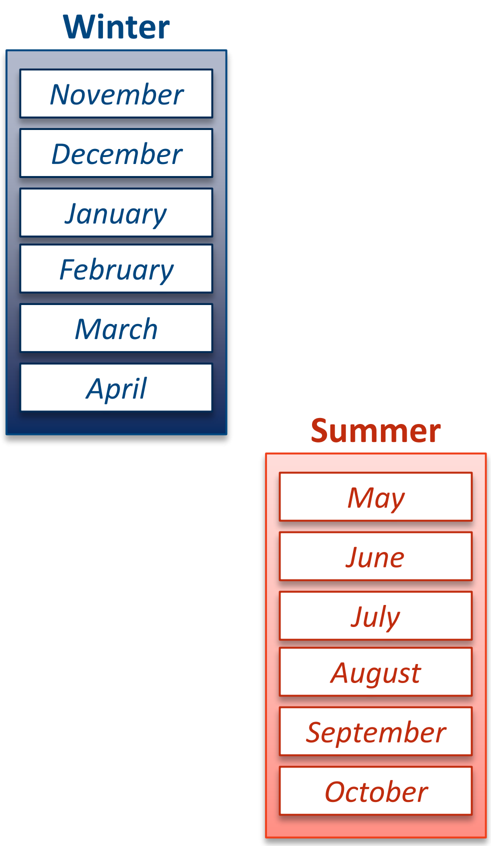
- NYISO originally implemented winter and summer obligation periods to accommodate seasonal resources, such as hydro imports from Quebec and increased winter capacity of thermal units
- Winter requirement is based on summer peak even though winter demand is lower (to spread payments more evenly across the year)
- Supported by strip and monthly spot auctions

The "**Grid in Transition**" plan will consider market design changes for a high-renewable fleet in its plan, including:

- Enhancing its resource adequacy model to account for shifts in shortage hours
- Revising resource capacity ratings
- Greater reliance on E&AS shortage pricing to complement RA changes

NYISO ICAP Market Design

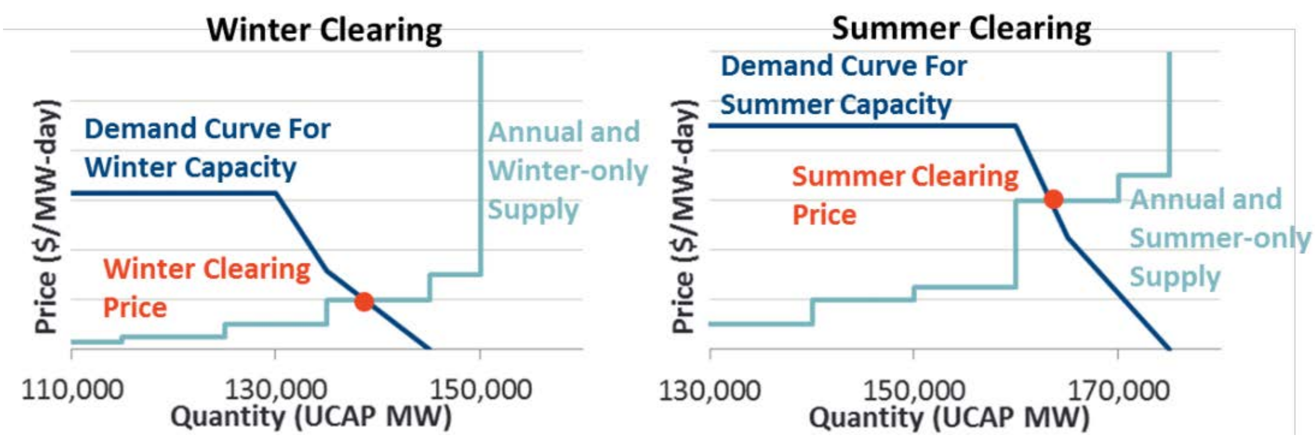
Seasonal strip auctions and month spot auctions



Ontario IESO proposed a seasonal capacity market

- Procurement target in each season reflects higher or lower peak demand forecasts in each season
- Resources qualify based on their contribution to RA need in each season
  - Allows for low-cost seasonal imports from both summer- and winter-peaking neighbors
- Clearing prices reflect each seasons' supply/demand balance, sending transparent price signal for marginal value of reliability
- Seasonal and annual bids are cleared together and co-optimized to procure the lowest-cost mix of seasonal and annual resources

Ontario's Proposed Seasonal Capacity Auctions



Source: The Brattle Group, "ICA Demand Curve Analysis: Preliminary Findings Regarding the Demand Curve for a Two-Season Auction," October 2019. Prepared for IESO stakeholder presentation.

Alberta's proposal for sub-annual RA

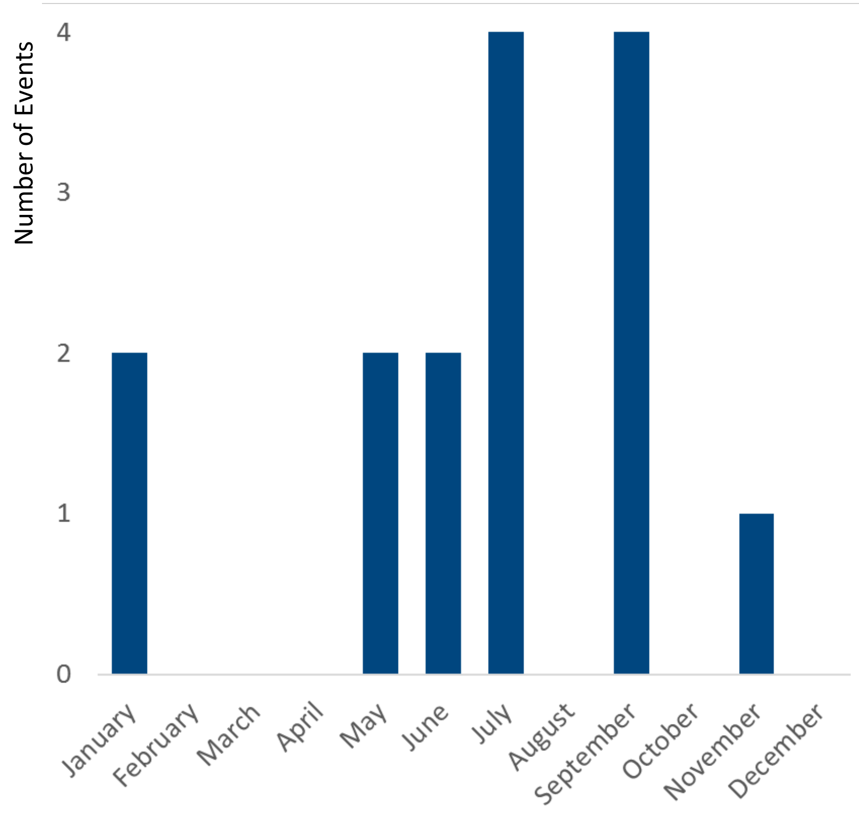
Required reserve margin: calculated using hourly (8760) probabilistic model to address **year-round shortage risks**

- Historically, events have occurred in primarily in summer, but several in winter and shoulder seasons

Resource accreditation: based on historical average availability in **tight conditions any time of year**

- 250 hours per year of tightest supply cushion over past five years
- Currently ~60% in summer, but evolving with changes in load patterns and fleet mix
- AESO originally preferred to use fewer hours (100), but increased due to stakeholder concern of excessive risk

Emergency Events in Alberta by Month, 2012-2018



Source: AESO, "Comprehensive Market Design: Rationale," 2018.

Appendix:
Resource Adequacy Metrics

Physical Resource Adequacy Metrics (1)

Metric	Description	Pros	Cons	Examples
Loss-of-Load Probability (LOLP)	The probability of demand exceeding the available resources during a given period. Can be calculated using either the daily peak loads or all hourly loads in a given period. Units: % chance of >= 1 event per 1 year	Easy to calculate and understand	Does not consider the duration or the size of an unserved load event.	Northwest Power and Conservation Council: 5% loss of load probability
Loss-of-Load Events (LOLEV)	The number of events in which some system load is not served in a year, irrespective of event duration (hrs) or depth (MW). One event in ten years translates to 0.1 loss-of-load events (LOLE) per year, regardless of the duration or depth of events. Units: Events per year	Easy to calculate and understand Most North American systems use this metric	Does not consider the duration or the size of the unserved load event.	Most U.S. Systems: 1 loss-of-load event per decade, or 0.1 event per year.
Loss-of-Load Expectation (LOLE)	The expected number of days per year for which the available generation capacity is insufficient to serve the daily peak demand. Units: Days with events per year	Easy to calculate and understand	Does not consider the size of the system and cannot be easily used to compare across different systems with different sizes	

Continued on next page

Physical Resource Adequacy Metrics (2)

Metric	Description	Pros	Cons	Examples
Loss-of-Load Hours (LOLH)	The expected number of hours per year when a system's demand is projected to exceed available supply. One day (24 hours) in ten years translates to 2.4 loss of load hours (LOLH) per year, regardless of the magnitude or number of such outages. Based on the summation of the probabilities for all hours in a year. Units: Hours per year	Considers the loss of load duration NERC recommended	Does not consider the size of the system and cannot be easily used to compare across different systems with different sizes	SPP: 2.4 loss of load hours per year
Normalized Expected Unserved Energy (EUE)	The expected number of MWh of load that will not be served in a given year as a result of demand exceeding the available supply across all hours. Can also be normalized as % of load not served. Units: % of expected annual load	Considers both the duration and magnitude of supply shortages. If normalized, it can be used to compare across systems of different size NERC recommended	Requires somewhat more sophisticated statistical methodologies	Alberta: Max annual EUE of 800 MWh Scandinavia: Max of 0.001% of total load shed each year Australia NEM: Max of 0.002% normalized EUE (not translated into an RA requirement)

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