ISO New England Tie Benefits Methodology Evaluation

Review of Probabilistic Analysis, Tie Benefits Methodologies of ISO-NE and Other ISO/RTOs, and Tie Benefits Evaluation Scope of Work

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RESOURCE ADEQUACY & ACCREDITATION

Overview

- Background and definition
  - Review background of tie benefits in New England, define the concept, highlight the reference from the Tariff, and discuss what effect tie benefits have on ISO-NE's resource adequacy requirements
- Probabilistic analysis
  - What is probabilistic analysis in general? How does it differ from deterministic analyses? How do the analyses determine the amount of assistance from neighboring Control Areas?
- Methodologies of other ISO/RTOs
  - How do other ISO/RTOs account for assistance from neighboring regions in their resource adequacy analyses?
- Scope and schedule for ISO-NE tie benefits methodology evaluation

Background

- As requested by NEPOOL, beginning in Q4 2023 and extending into Q4 2024, the ISO is conducting and reporting on a broad evaluation of the reliability inputs for tie benefits, in which the ISO will evaluate past performance and modeling of tie benefits and expected short- to mid-term future performance
- Any market or contract changes that may be identified as a result of this evaluation would need to be discussed and scoped separately after the evaluation
- This effort is distinct from the ISO’s current proposal under RCA to incorporate summer and winter components in its accounting for seasonality of tie benefits in the Forward Capacity Market (FCM)

Important Note

- This presentation describes ISO-NE's current tie benefits methodology
  - The presentation does not include any ISO-NE recommendation or position
- It is important to analyze the current methodology before developing recommendations
  - Additionally, ISO-NE aims to first vet the forward resource capacity accreditation (RCA) design through a fulsome stakeholder process before making any recommendations for change in the current tie benefits methodology
  - Having a more precise view of the market design options in play will allow ISO-NE to further refine and tailor any tie benefits recommendations to the most relevant design constructs
- ISO-NE welcomes stakeholder discussion and feedback on this complex topic

WHAT ARE TIE BENEFITS?

What do they represent and how do they factor into ISO-NE’s resource adequacy criteria?

What are tie benefits?

- Tie benefits reflect the assumed amount of emergency assistance from neighboring Control Areas that New England could rely on, without jeopardizing reliability in New England or the neighboring Control Areas, in the event of a capacity shortage in New England
- The calculation of tie benefits is described in Market Rule 1, Section III.12.9 of the Tariff
  - *"Tie benefits shall be calculated using a probabilistic multi-area reliability model, by comparing the LOLE* for the New England system before and after interconnecting the system to the neighboring Control Areas. To quantify tie benefits, firm capacity equivalents shall be added until the LOLE of the isolated New England Control Area is equal to the LOLE of the interconnected New England Control Area."*
- The interconnections that tie benefits apply to is also described in Section III.12.9
  - *"Tie benefits shall be calculated only for interconnections (1) without Capacity Network Import Interconnection Service or Network Import Interconnection Service or (2) that have not requested Capacity Network Import Interconnection Service or Network Import Interconnection Service with directly interconnected neighboring Control Areas with which the ISO has in effect agreements providing for emergency support to New England, including but not limited to inter-Control Area coordination agreements, emergency aid agreements and the NPCC Regional Reliability Plan."*

** Loss of Load Expectation*

What are tie benefits? cont.

- The Northeast Power Coordinating Council (NPCC), the Regional Entity (RE) for ISO-NE, imposes several mandatory regional reliability standards that ISO-NE must comply with:
  - NPCC Directory 1 – Design and Operation of the Bulk Power System, Section 3 on Resource Adequacy:
    - R4: *"Each Planning Coordinator [("PC")] or Resource Planner [("RP")] shall probabilistically evaluate **resource** adequacy of its Planning Coordinator **Area** portion of the **bulk power system** to demonstrate that the loss of **load** expectation (LOLE) of disconnecting **firm load** due to **resource** deficiencies is, on average, no more than 0.1 days per year."*
    - R4.1: *"[each PC or RP shall] Make due allowances for **demand** uncertainty, scheduled outages and deratings, forced outages and deratings, <u>assistance over interconnections with neighboring Planning Coordinator **Areas**</u>, transmission transfer capabilities, and **capacity** and/or **load** relief from available operating procedures."* [emphasis added]
  - NPCC defines Capacity Benefit Margin (CBM) in their Glossary of Terms
    - *"CBM is defined as that amount of transmission transfer capability reserved by **load** serving entities to ensure access to **generation** from interconnected systems to meet **generation** reliability requirements."*
    - While this definition uses a different term (CBM), the definition effectively describes how ISO-NE models tie benefits

What are tie benefits? cont.

- Section III.12.7.4 of the Tariff – Load and Capacity Relief, describes actions from ISO-NE Operating Procedure No. 4 – Action During a Capacity Deficiency (OP-4) that are included in the calculation of the Installed Capacity Requirement (ICR)
  - Subsection (b) of OP-4 states:
    "(b) [ISO-NE shall] ***Arrange for available Emergency energy from Market Participants or neighboring Control Areas.*** *These actions are included in the calculation through the use of tie benefits to meet system needs. The MW value of tie benefits is calculated in accordance with Section III.12.9."*
- Note: this language implies that ISO-NE would rely on tie benefits when the system **has already declared or trying to avoid declaring OP-4** and a Capacity Scarcity Condition is likely to occur

What are tie benefits? cont.

- OP-4 Appendix A – Estimates of Generation and Load Relief, lists ISO-NE's System Operations' estimates of MW relief from the different OP-4 actions
  - Action 5: Arrange to purchase available emergency capacity and energy, or energy only, (if capacity backing is not available) from Market Participants (MPs) or neighboring Reliability Coordinator Areas (RCAs)/ Balancing Authority Areas (BAAs). Control Area-to-Control Area emergency transactions will normally be used as a last resort, when market-based Emergency Energy transactions (EETs) are not available, or not available in a timely fashion
    - Potential MW relief to be purchased listed as *"Variable (could be between 0 and 1,000 MW)"*

What is the history of tie benefits?

- New England has used tie benefits for decades in its resource adequacy calculations
- The 2006 FCM Settlement Agreement stated "the ICR shall be calculated assuming appropriate tie benefits, if any, from adjacent Control Areas"
- In 2007, FERC issued orders approving the ISO's tie benefits methodology
- FERC approved revisions to the methodology in 2010
  - Changed the "as is" methodology to the "at criteria" (every area modeled at LOLE = 0.1 days/year) methodology
- FERC approved the tie benefits methodology for the third annual reconfiguration auction in 2011

How are tie benefits used in ICR calculations?

- Tie benefits are used in the calculation of the ICR used in the Forward Capacity Auction (FCA)
  - An equation representing the ICR calculation is included in the ICR Guide posted on the ISO website

$$ICR = \frac{capacity - tie\ benefits - OP4\ load\ relief}{1 + \frac{ALCC}{APk}} + HQICCs$$

  - Section I.2.2 of the Tariff: *"HQ Interconnection Capability Credit (HQICC) is a monthly value reflective of the annual installed capacity benefits of the Phase I/II HVDC-TF, as determined by the ISO, using a standard methodology on file with the Commission, in conjunction with the setting of the Installed Capacity Requirement. …"*
  - Using tie benefits in the ICR [and related values] calculations satisfies NPCC Directory #1 Requirement 4.1: to include, *"…assistance over interconnections with neighboring Planning Coordinator **Areas**…"*
  - Section III.12.7.4 (b) of the Tariff: *"**Arrange for available Emergency energy from Market Participants or neighboring Control Areas.** These actions are included in the calculation through the use of tie benefits to meet system needs…"* [emphasis added]
- Using tie benefits satisfies both the NPCC Directory #1 requirement and our Tariff obligation

How do tie benefits affect the FCA?

- Three hypothetical amounts of tie benefits (current, min, and max) will be used to show how tie benefits are reflected in the FCA
- Things to note:
  - Assume tie benefits have a 1-to-1 ratio with net ICR
  - Assume that ISO-NE procures the full amount of net ICR in the FCA (no MRI demand curve)
  - Numbers are rounded for simplicity
  - Load Serving Entities (LSEs) that are Interconnection Rights Holders (IRH) are credited with Hydro Québec Interconnection Capability Credits (HQICCs) to reduce their load obligation that purchases the net ICR

Assumption (MW)	Current	Min	Max
Summer Peak		27,000	
Total Resources required to meet LOLE=0.1 day/yr		33,000	
Total TB	2,000	0	3,700
TB – Phase II (HQICC) (external resources)	1,000	0	1,400
TB – Other ties (external resources)	1,000	0	2,300
Net ICR (internal resources)	31,000	33,000	29,300

How do tie benefits / HQICCs affect payments?

- Load that does not have HQICCs is required to contribute to the purchase of net ICR in the FCA
- In the current scenario, 26,000 MW of load (27,000 MW load – 1,000 MW HQICCs) pays for 31,000 MW of capacity (33,000 MW ICR – 2,000 MW TB)
  - 1.19 MW of capacity purchased per 1 MW of non-HQICC credited load
- In the min tie benefits scenario, 27,000 MW of load (27,000 – 0) pays for 33,000 MWs of capacity (33,000 – 0)
  - 1.22 MW of capacity purchased per 1 MW of non-HQICC credited load
- In the max tie benefits scenario, 25,600 MW of load (27,000 – 1,400) pays for 29,300 MWs of capacity (33,000 – 3,700)
  - 1.14 MW of capacity purchased per 1 MW of non-HQICC credited load

How are tie benefits calculated?

- As already described, Section III.12.9 of the Tariff states:
  - *"Tie benefits shall be calculated using a <u>probabilistic multi-area reliability model</u>, by comparing the LOLE for the New England system before and after interconnecting the system to the neighboring Control Areas. To quantify tie benefits, firm capacity equivalents shall be added until the LOLE of the isolated New England Control Area is equal to the LOLE of the interconnected New England Control Area."* (Emphasis added.)

- What is a "probabilistic multi-area reliability model?"
  - The next section of this presentation explains that type of analysis

PROBABILISTIC ANALYSIS

What is it, how does it differ from a deterministic analysis, and how does it work?

Language and examples from the GE Multi-Area Reliability Simulation (GE MARS) Introductory Training ©2023 have been included with GE authorization

Resource Adequacy

- Resource adequacy is the ability of the generation fleet to meet the system load requirement
- ISO-NE performs two primary types of analyses to determine the resource adequacy of the system:
  - Deterministic: Short-term operating indices
    - *E.g.*, daily morning report and seasonal operational capability analyses detail excess capacity for a given operating day or season
  - Probabilistic: long-term planning indices
    - *E.g.*, ICR and tie benefits analyses detail loss of load probability (LOLP), daily and hourly LOLE, and expected unserved energy (EUE)

Probabilistic Analysis

- Probabilistic analysis can be broken down into two general categories:
  - Analytical: represent reliability using mathematical functions based on probability distributions (*e.g.*, transmission planning needs assessments calculating the expected generation out-of-service for the base case using historical EFORd values and same probability curves)
  - Simulation: represent reliability by simulating trials of the actual random behavior of the system (*e.g.*, tie benefits and ICR analyses)
- The following slides contain examples that use analytical methods to convey probabilistic concepts
- Thereafter, the use of simulation methods used in conducting ISO-NE's probabilistic analyses is explained

ANALYSIS METHOD

Analytical Method – 2 Generator Example

A system has 2 generators, each generator has a 50 MW total output and a 5% outage probability – what is the probability of 50 MW or greater being out-of-service?

- Step 1: Create a table with all possible combinations

Unit 1 Capacity Out	Unit 2 Capacity Out	Total Capacity Out	Probability Calculation	Probability
0	0	0	0.95*0.95	0.9025
0	50	50	0.95*0.05	0.0475
50	0	50	0.05*0.95	0.0475
50	50	100	0.05*0.05	0.0025

Analytical Method – 2 Generator Example, cont.

A system has 2 generators, each generator has a 50 MW total output and a 5% outage probability – what is the probability of 50 MW or greater being out-of-service?

- Step 2: Create a table of all enumerated states
- Step 3: Select the cumulative probability → 9.75% probability 50 MW or greater is out-of-service (3 states: Unit 1 out, Unit 2 out, Unit 1&2 out)

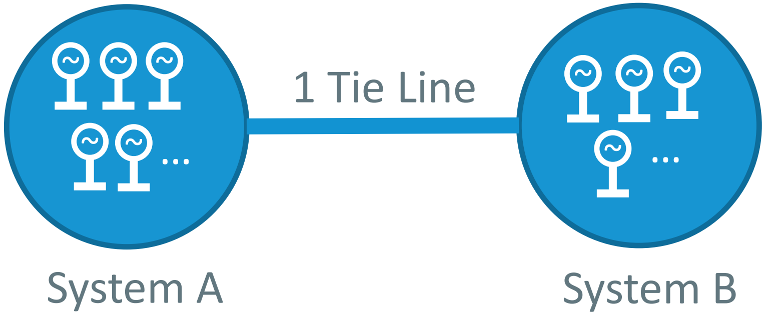
Total Capacity Out	State Probability	Cumulative Probability
0	0.9250	1.0000
50	0.0950	0.0975
100	0.0025	0.0025

Analytical Method – 2 Generator Example, cont.

- Continuing with the current example, if the system had a load of 45 MW, what is the loss of load probability?
- Because the only scenario where load could not be served is with both units out, then the probability of that state is 0.25%
- As the number of generators in a system increases, this method has 2^n combinations
  - A 300 generator system has 2.04×10^{90} combinations
  - This method becomes unmanageable quickly
  - The simulation method described starting on slide 35 addresses this problem

Analytical Method – Transmission Interconnection

- The next example shows how the LOLP changes when two systems are interconnected
- System A
  - 10 identical 20 MW generators with 5% EFORd*
  - 180 MW constant load
- System B
  - 8 identical 50 MW generators with 9% EFORd
  - 320 MW constant load
- Interconnection
  - One tie line with ∞ and 50 MW



*Equivalent Forced Outage Rate on demand

Analytical Method – Trans. Interconnection, cont.

- Capacity Outage Probability Tables for Systems A and B

System A

Cap. Out MW	Reserve	Probability
0	20	0.598737
20	0	0.315125
40	-20	0.074635
60	-40	0.010475
80	-60	0.000965
100	-80	0.000061
120	-100	0.000003

Isolated LOLP **0.086138**

System B

Cap. Out MW	Reserve	Probability
0	80	0.470253
50	30	0.372068
100	-20	0.128793
150	-70	0.025475
200	-120	0.003149
250	-170	0.000249
300	-220	0.000012

Isolated LOLP **0.157678**

- The isolated LOLP is the summation of probabilities where reserves are negative
- The next step is to tie the two systems together

Analytical Method – Trans. Interconnection, cont.

- Calculate the combined probabilities for each A/B state

				System B						
	Cap. Out			0	50	100	150	200	250	300
	MW	Reserve		80	30	-20	-70	-120	-170	-220
			Probability	0.470253	0.372068	0.128793	0.025475	0.003149	0.000249	0.000012
System A	0	20	0.598737	0.281558	0.222771	0.077113	0.015253	0.001886	0.000149	0.000007
System A	20	0	0.315125	0.148188	0.117248	0.040586	0.008028	0.000992	0.000079	0.000004
System A	40	-20	0.074635	0.035097	0.027769	0.009612	0.001901	0.000235	0.000019	0.000001
System A	60	-40	0.010475	0.004926	0.003897	0.001349	0.000267	0.000033	0.000003	0.000000
System A	80	-60	0.000965	0.000454	0.000359	0.000124	0.000025	0.000003	0.000000	0.000000
System A	100	-80	0.000061	0.000029	0.000023	0.000008	0.000002	0.000000	0.000000	0.000000
System A	120	-100	0.000003	0.000001	0.000001	0.000000	0.000000	0.000000	0.000000	0.000000

System A Isolated LOLP	**0.086138**
System B Isolated LOLP	**0.157679**

Analytical Method – Trans. Interconnection, cont.

Unlimited Interconnection

- System B is supporting System A, update the reserve for System A

				System B						
	Cap. Out			0	50	100	150	200	250	300
	MW	Reserve		80	30	-20	-70	-120	-170	-220
			Probability	0.470253	0.372068	0.128793	0.025475	0.003149	0.000249	0.000012
System A	0	20	0.598737	0.281558	0.222771	0.077113	0.015253	0.001886	0.000149	0.000007
System A	20	0	0.315125	0.148188	0.117248	0.040586				0.000004
System A	40	-20	0.074635	0.035097	0.027769	0.009612				0.000001
System A	60	-40	0.010475	0.004926	0.003897	0.001349				0.000000
System A	80	-60	0.000965	0.000454	0.000359	0.000124	0.000025	0.000003	0.000000	0.000000
System A	100	-80	0.000061	0.000029	0.000023	0.000008	0.000002	0.000000	0.000000	0.000000
System A	120	-100	0.000003	0.000001	0.000001	0.000000	0.000000	0.000000	0.000000	0.000000
				100	50	20	20	20	20	20
				80	30	0	0	0	0	0
				60	10	-20	-20	-20	-20	-20
				40	-10	-40	-40	-40	-40	-40
				20	-30	-60	-60	-60	-60	-60
				0	-50	-80	-80	-80	-80	-80
				-20	-70	-100	-100	-100	-100	-100

When System B is deficient, it cannot supply additional reserves to System A, so System A reserves stay the same.

Analytical Method – Trans. Interconnection, cont.

Unlimited Interconnection

- System B is supporting System A, update the reserve for System A

			System B						
Cap. Out			0	50	100	150	200	250	300
MW	**Reserve**		80	30	-20	-70	-120	-170	-220
		Probability	0.470253	0.372068	0.128793	0.025475	0.003149	0.000249	0.000012
System A 0	20	0.598737	0.281558	0.222771	0.077113	0.015253	0.001886	0.000149	0.000007
20	0	0[illegible]	[illegible]	[illegible]	[illegible]586	0.008028	0.000992	0.000079	0.000004
40	-20	0[illegible]	[illegible]	[illegible]	[illegible]512	0.001901	0.000235	0.000019	0.000001
60	-40	0[illegible]	[illegible]	[illegible]	[illegible]349	0.000267	0.000033	0.000003	0.000000
80	-60	0.000965	0.000454	0.000359	0.000124	0.000025	0.000003	0.000000	0.000000
100	-80	0.000061	0.000029	0.000023	0.000008	0.000002	0.000000	0.000000	0.000000
120	-100	0.000003	0.000001	0.000001	0.000000	0.000000	0.000000	0.000000	0.000000

When System B has additional reserves, it can contribute the full amount to System A. As a result, System A reserves increase by the amount of excess reserves in System B.

100	50	20	20	20	20	20
80	30	0	0	0	0	0
60	10	-20	-20	-20	-20	-20
40	-10	-40	-40	-40	-40	-40
20	-30	-60	-60	-60	-60	-60
0	-50	-80	-80	-80	-80	-80
-20	-70	-100	-100	-100	-100	-100

Analytical Method – Trans. Interconnection, cont.

Unlimited Interconnection

- The new LOLP for System A is the sum of probabilities where updated reserve is negative

			System B						
Cap. Out MW	**Reserve**	**Probability**	0	50	100	150	200	250	300
			[illegible]	[illegible]	[illegible]	-70	-120	-170	-220
			[illegible]	[illegible]	[illegible]	0.025475	0.003149	0.000249	0.000012
System A 0	20	0.598737	[illegible]	[illegible]	[illegible]	0.015253	0.001886	0.000149	0.000007
20	0	0.315125	0.148188	0.117248	0.040580	0.008028	0.000992	0.000079	0.000004
40	-20	0.074635	0.035097	0.027769	0.009612	0.001901	0.000235	0.000019	0.000001
60	-40	0.010475	0.004926	0.003897	0.001349	0.000267	0.000033	0.000003	0.000000
80	-60	0.000965	0.000454	0.000359	0.000124	0.000025	0.000003	0.000000	0.000000
100	-80	0.000061	0.000029	0.000023	0.000008	0.000002	0.000000	0.000000	0.000000
120	-100	0.000003	0.000001	0.000001	0.000000	0.000000	0.000000	0.000000	0.000000

The cumulative LOLP for System A with the interconnection is the sum of the probabilities of the combined states with negative reserves.

		100	50	20	20	20	20	20
System A Isolated LOLP	**0.086138**	80	30	0	0	0	0	0
		60	10	-20	-20	-20	-20	-20
Interconnected LOLP	**0.017864**	40	-10	-40	-40	-40	-40	-40
(Unlimited Interconnection)		20	-30	-60	-60	-60	-60	-60
		0	-50	-80	-80	-80	-80	-80
		-20	-70	-100	-100	-100	-100	-100

Analytical Method – Trans. Interconnection, cont.

Unlimited Interconnection

- System A is now supporting System B, update the reserve for System B

			System B						
Cap. Out			0	50	100	150	200	250	300
MW	**Reserve**		80	30	-20	-70	-120	-170	-220
		Probability	0.470253	0.372068	0.128793	0.025475	0.003149	0.000249	0.000012
System A 0	20	0.598737	0.281558						000007
20	0	0.315125	0.148188						000004
40	-20	0.074635	0.035097						000001
60	-40	0.010475	0.004926	0.003897	[illegible]	[illegible]	[illegible]	0.000003	0.000000
80	-60	0.000965	0.000454	[illegible]				0.000000	0.000000
100	-80	0.000061	0.000029	[illegible]				0.000000	0.000000
120	-100	0.000003	0.000001	0.000001	0.000000	0.000000	0.000000	0.000000	0.000000
			100	50	0	-50	-100	-150	-200
System B Isolated LOLP		**0.157679**	80	30	-20	-70	-120	-170	-220
			80	30	-20	-70	-120	-170	-220
			80	30	-20	-70	-120	-170	-220
			80	30	-20	-70	-120	-170	-220
			80	30	-20	-70	-120	-170	-220
			80	30	-20	-70	-120	-170	-220

When System A has additional reserves, it can contribute the full amount to System B. As a result, System B reserves increase by the amount of excess reserves in System A.

When System A is deficient, it cannot supply additional reserves to System B, so System B reserves stay the same

Analytical Method – Trans. Interconnection, cont.

Unlimited Interconnection

- The new LOLP for System B is the sum of probabilities where updated reserve is negative

				System B						
	Cap. Out			0	50	100	150	200	250	300
	MW	**Reserve**		80	30	-20	-70	-120	-170	-220
			Probability	0.470253	0.372068	0.128793	0.025475	0.003149	0.000249	0.000012
System A	0	20	0.598737	0.281558	0.222771	0.077113	0.015253	0.001886	0.000149	0.000007
System A	20	0	0.315125	0.148188	0.117248	0.040586	0.008028	0.000992	0.000079	0.000004
System A	40	-20	0.074635	0.035097	0.027769	0.009612	0.001901	0.000235	0.000019	0.000001
System A	60	-40	0.010475	0.004926	0.003897	0.001349	0.000267	0.000033	0.000003	0.000000
System A	80	-60	0.000965	0.000454	0.000359	0.000124	0.000025	0.000003	0.000000	0.000000
System A	100	-80	0.000061	0.000029	0.000023	0.000008	0.000002	0.000000	0.000000	0.000000
System A	120	-100	0.000003	0.000001	0.000001	0.000000	0.000000	0.000000	0.000000	0.000000
				100	50	0	-50	-100	-150	-200
	System B Isolated LOLP		**0.157679**	80	30	-20	-70	-120	-170	-220
				80	30	-20	-70	-120	-170	-220
	Interconnected LOLP (Unlimited Interconnection)		**0.080566**	80	30	-20	-70	-120	-170	-220
				80	30	-20	-70	-120	-170	-220
				80	30	-20	-70	-120	-170	-220
				80	30	-20	-70	-120	-170	-220

Analytical Method – Trans. Interconnection, cont.

- As demonstrated, the LOLP of each system decreases when the two systems can share excess reserves with each other

LOLP	System A	System B
Isolated	0.086138	0.157679
Interconnected (unlimited tie)	0.017864	0.080566

- What changes if the interconnection is limited to 50 MW?
  - This is analyzed in the slides that follow

Analytical Method – Trans. Interconnection, cont.

50 MW Interconnection

- System B is supporting System A up to 50 MW, update the reserve for System A

			System B						
Cap. Out			0	50	100	150	200	250	300
MW	**Reserve**		~~80~~ 50	30	-20	-70	-120	-170	-220
		Probability	0.470253	0.372068	0.128793	0.025475	0.003149	0.000249	0.000012
System A 0	20	0.598737	0.281558	0.222771	0.077113	0.015253	0.001886	0.000149	0.000007
20	0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0.000004
40	-20	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0.000001
60	-40	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0.000000
80	-60	[illegible]	[illegible]	[illegible]	[illegible]	0.000025	0.000003	0.000000	0.000000
100	-80	[illegible]	[illegible]	[illegible]	[illegible]	0.000002	0.000000	0.000000	0.000000
120	-100	0.000003	0.000001	0.000001	0.000000	0.000000	0.000000	0.000000	0.000000

When System B has additional reserves, it can contribute the full amount to System A (up to 50 MW). As a result, System A reserves increase by the amount of excess reserves in System B (up to 50 MW).

When System B is deficient, it cannot supply additional reserves to System A, so System A reserves stay the same.

System A Isolated LOLP **0.086138**

0	50	100	150	200	250	300
70	50	20	20	20	20	20
50	30	0	0	0	0	0
30	10	-20	-20	-20	-20	-20
10	-10	-40	-40	-40	-40	-40
-10	-30	-60	-60	-60	-60	-60
-30	-50	-80	-80	-80	-80	-80
-50	-70	-100	-100	-100	-100	-100

Analytical Method – Trans. Interconnection, cont.

50 MW Interconnection

- The new LOLP for System A is the sum of probabilities where updated reserve is negative (note 2 additional boxes of negative reserve)

				System B						
	Cap. Out			0	50	100	150	200	250	300
	MW	**Reserve**		~~80~~ 50	30	-20	-70	-120	-170	-220
			Probability	0.470253	0.372068	0.128793	0.025475	0.003149	0.000249	0.000012
System A	0	20	0.598737	0.281558	0.222771	0.077113	0.015253	0.001886	0.000149	0.000007
System A	20	0	0.315125	0.148188	0.117248	0.040586	0.008028	0.000992	0.000079	0.000004
System A	40	-20	0.074635	0.035097	0.027769	0.009612	0.001901	0.000235	0.000019	0.000001
System A	60	-40	0.010475	0.004926	0.003897	0.001349	0.000267	0.000033	0.000003	0.000000
System A	80	-60	0.000965	0.000454	0.000359	0.000124	0.000025	0.000003	0.000000	0.000000
System A	100	-80	0.000061	0.000029	0.000023	0.000008	0.000002	0.000000	0.000000	0.000000
System A	120	-100	0.000003	0.000001	0.000001	0.000000	0.000000	0.000000	0.000000	0.000000
				70	50	20	20	20	20	20
	System A Isolated LOLP		**0.086138**	50	30	0	0	0	0	0
				30	10	-20	-20	-20	-20	-20
	Interconnected LOLP		**0.017864**	10	-10	-40	-40	-40	-40	-40
	(Unlimited Interconnection)			-10	-30	-60	-60	-60	-60	-60
	Interconnected LOLP		**0.018346**	-30	-50	-80	-80	-80	-80	-80
	(50 MW Interconnection)			-50	-70	-100	-100	-100	-100	-100

Analytical Method – Trans. Interconnection, cont.

50 MW Interconnection

- The LOLP for System B 50 MW interconnection does not change because the excess reserve of System A never exceeds 50 MW

				System B						
	Cap. Out			0	50	100	150	200	250	300
	MW	**Reserve**		80	30	-20	-70	-120	-170	-220
			Probability	0.470253	0.372068	0.128793	0.025475	0.003149	0.000249	0.000012
System A	0	20	0.598737	0.281558	0.222771	0.077113	0.015253	0.001886	0.000149	0.000007
System A	20	0	0.315125	0.148188	0.117248	0.040586	0.008028	0.000992	0.000079	0.000004
System A	40	-20	0.074635	0.035097	0.027769	0.009612	0.001901	0.000235	0.000019	0.000001
System A	60	-40	0.010475	0.004926	0.003897	0.001349	0.000267	0.000033	0.000003	0.000000
System A	80	-60	0.000965	0.000454	0.000359	0.000124	0.000025	0.000003	0.000000	0.000000
System A	100	-80	0.000061	0.000029	0.000023	0.000008	0.000002	0.000000	0.000000	0.000000
System A	120	-100	0.000003	0.000001	0.000001	0.000000	0.000000	0.000000	0.000000	0.000000
				100	50	0	-50	-100	-150	-200
	System B Isolated LOLP		**0.157679**	80	30	-20	-70	-120	-170	-220
				80	30	-20	-70	-120	-170	-220
	Interconnected LOLP (Unlimited Interconnection)		**0.080566**	80	30	-20	-70	-120	-170	-220
				80	30	-20	-70	-120	-170	-220
	Interconnected LOLP (50 MW Interconnection)		**0.080566**	80	30	-20	-70	-120	-170	-220
				80	30	-20	-70	-120	-170	-220

Analytical Method – Trans. Interconnection, cont.

- This example shows the difference between capacity limited systems (unlimited interconnection) vs. an interconnection limited system (50 MW interconnection)
- With the interconnection limited to 50 MW, System B cannot transfer its full amount of excess capacity to System A, so the LOLP for System A increases from the unlimited interconnection

LOLP	System A	System B
Isolated	0.086138	0.157679
Interconnected (unlimited tie)	0.017864	0.080566
Interconnected (50 MW)	0.018346	0.080566

- This concept is the basis for incorporating tie benefits into ISO-NE's ICR calculation methodology

SIMULATION METHOD

Simulation Method

- As discussed earlier, the analytical method is infeasible when trying to assess a system the size of NPCC
- Stochastic simulation, commonly referred to as Monte Carlo simulation, is an alternative to the analytical method described thus far for ***estimating*** reliability indices
- Unlike the analytic approach, there is no set mathematical representation for Monte Carlo simulation – it is instead based on a series or random numbers generated by a computer
- By taking random samples of various system operating conditions, an estimate of the system reliability can be obtained without knowing an exact numerical formulation

Simulation Method, cont.

$$Loss\ of\ Load\ Probability\ (LOLP) = \lim_{N\to\infty} \frac{1}{N} \sum_{N} Loss\ of\ Load$$

- Using the simulation method, the loss of load probability is the average probability as the number of random samples, N, approaches infinity
- If the number of samples is sufficiently large, then the simulation method should converge to a value that is very close to the value that would be derived using the analytic method
  - The ISO typically will run 1,000 to 5,000 replications during analyses
- The simulation method is just another method to solving the same problem

Simulation Method, cont.

- The number of samples N is determined by reaching a standard error of the expected value of the simulated reliability indices (LOLP, LOLE, EUE, etc.)
  - *E.g.*, another sample won't change the average by a specified tolerance

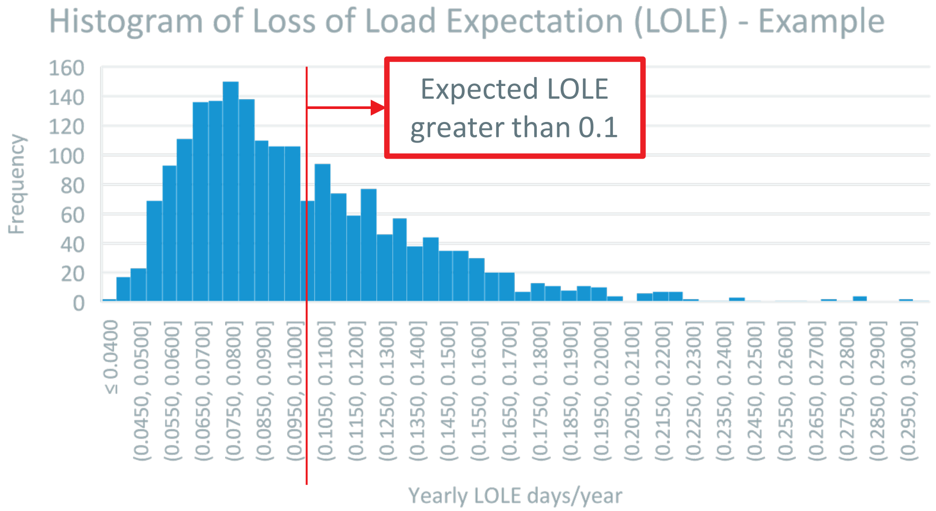
- Expected value: $$\bar{I} = \frac{1}{N}\sum_{i=1}^{N} I_i$$

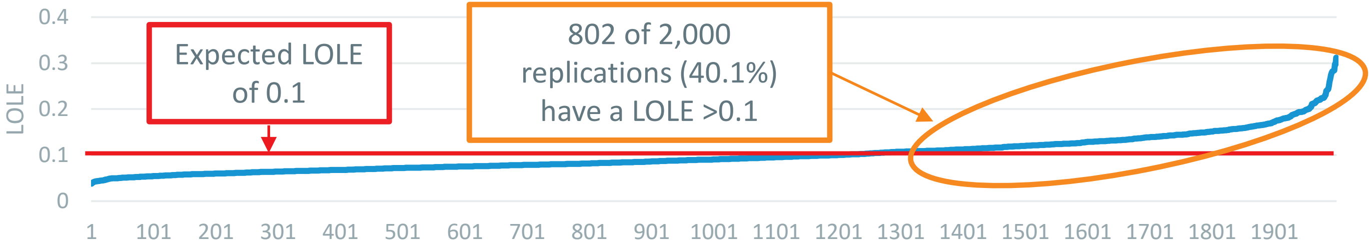
- Standard Error: $$Standard\ Error\ of\ \bar{I} = \frac{S\bar{I}}{\bar{I}}$$

  Where: $$S\bar{I} = \sqrt{\frac{S^2}{N}} \qquad S^2 = \frac{1}{N}\sum_{i=1}^{N}\left(I_i - \bar{I}\right)^2$$

Expected Value for Reliability Indices

- It is very important to note that all the reliability indices posted for a simulation run are ***<u>expected</u>*** values (*e.g.*, average), not minimums, maximums, etc.
- A LOLE of 0.1 days/year in an ICR simulation can have a wide range of replication results





Chronological Monte Carlo Simulation

- For each replication (sample N_i) in the simulation, Monte Carlo chronological simulation involves the basic 3 step process
  - Step 1: Generate random operating histories for all units in the system
  - Step 2: Compare the total available capacity in each hour with a chronological demand profile
  - Step 3: Aggregate statistics when load > available generation
    - This state denotes a loss of load

Chronological Monte Carlo Simulation, cont.

- How does ISO-NE create random operating profiles for generators based on their forced outage rates?
- A generator's basic forced outage rate is calculated as follows:

$$Forced\ Outage\ Rate = \frac{\lambda}{\lambda + \mu} = \frac{r}{m + r}$$

$\lambda = Time\ Unavailable$ $\quad$ $r = Mean\ Time\ to\ Repair = 1 / \mu$

$\mu = Time\ Available$ $\quad$ $m = Mean\ Time\ to\ Failure = 1 / \lambda$

Chronological Monte Carlo Simulation, cont.

- Time to Failure (TtF) and Time to Repair (TtR) can be estimated by transforming uniform random numbers (U) into an exponential distribution around the mean time to failure (m), and mean time to repair (r)

$$TtF = -m \ln(U_1)$$

$$TtR = -r \ln(U_2)$$

Chronological Monte Carlo Simulation, cont.

To create an outage profile for each generator, the simulation follows the following steps:

1. Assume the generator starts at full rated capacity

2. Generate a uniform random number (U_1) in the range 0-1

3. Determine the Time to Failure (TtF)

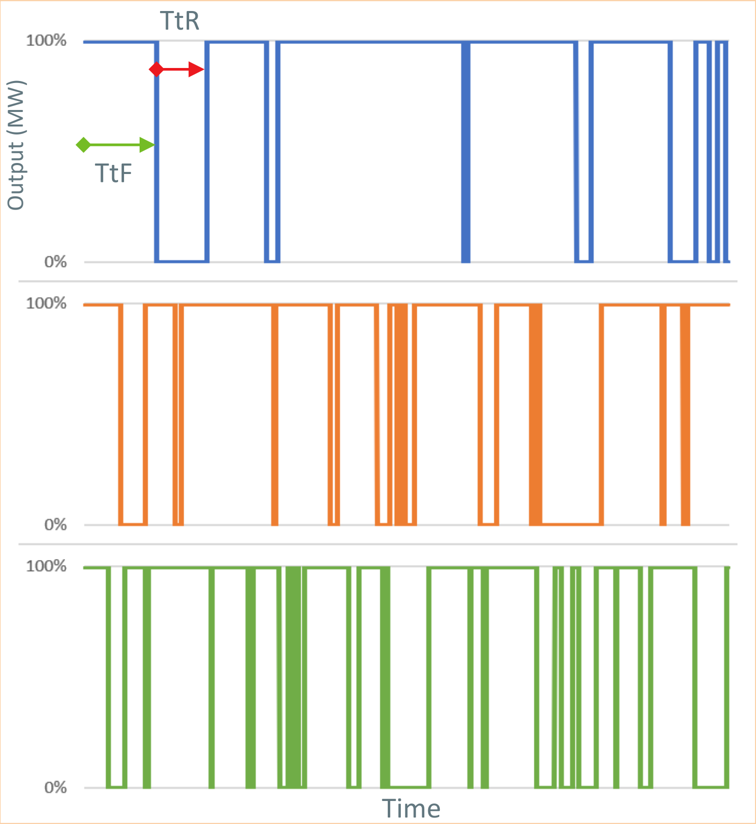
$$TtF = -m \ln(U_1)$$

4. After the time to failure has elapsed, turn the generator offline, then generate another uniform random number (U_2) in the range 0-1

5. Determine the Time to Repair (TtR)

$$TtR = -r \ln(U_2)$$

6. After the time to repair has elapsed, turn the generator online, then go to step 2



Probabilistic Methodology Key Takeaways

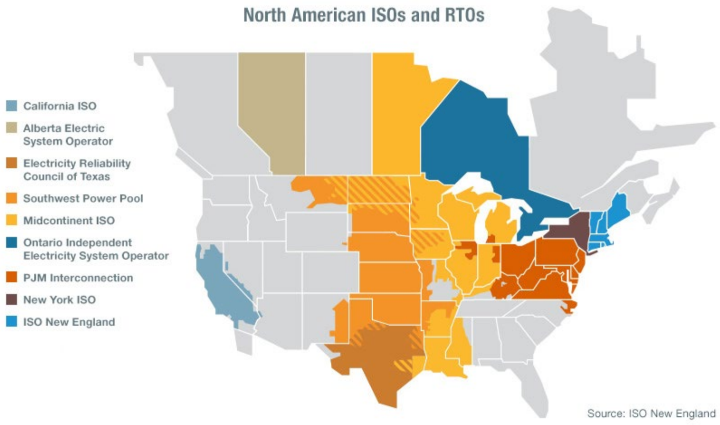
- Resource adequacy probabilistic analyses can be performed using two different methods: analytical and simulation
- ISO-NE uses the simulation method to compute the reliability indices for the system due to the size and complexity of calculations
- The interconnection of two neighboring systems allows for sharing of excess resources up to the limit of the transmission interconnection to reduce each system's LOLP/LOLE/EUE
- The chronological Monte Carlo simulation method produces ***expected*** values that are the average of a wide range of values from thousands of replications

METHODOLOGIES OF OTHER REGIONS

How do other ISOs/RTOs factor assistance from neighboring regions in their resource adequacy analyses?

Methodologies of Other ISOs/RTOs

- The ISO reached out to several other ISOs/RTOs in the US and Canada to explore how each region factors in assistance from neighboring regions in its resource adequacy analyses
- The following slides provide brief summaries of the resource adequacy analyses that each ISO/RTO performs, and describe how each of them factors in outside assistance
  - New York Independent System Operator (NYISO), PJM, Midcontinent Independent System Operator (MISO), California ISO (CAISO), Southwest Power Pool (SPP), Electric Reliability Council of Texas (ERCOT), Independent Electric System Operator (IESO – Ontario), and Alberta Electric System Operator (AESO)



NYISO: Overview

- Capacity market:
  - Prompt, seasonal capacity market

- Neighbors with IESO to the west, HQ to the north, ISO-NE to the east, and PJM to the south

Fast Facts

- **Service territory:** 54,556 square miles
- **Generating units:** 760
- **Miles of transmission:** 11,173
- **Peak demand (2019):** 30,397 MW

NYISO: Resource Adequacy

- Resource adequacy requirements are established annually by the New York State Reliability Council (NYSRC), which sets the Installed Reserve Margin (IRM) for the system
- Annual requirement: New York Control Area (NYCA) Minimum Installed Capacity Requirement =
  Forecasted NYCA Peak Load x (1+IRM)
- Criterion: uses NPCC Directory #1 requirement of
  LOLE = 0.1 days/year
- Analysis type: a probabilistic multi-area reliability model running sequential Monte Carlo simulations is used to calculate NYISO's IRM
- Software: GE MARS

NYISO: Tie Benefits Methodology

- Terminology: the equivalent term that NYISO uses for tie benefits is emergency assistance (EA)
- Methodology:
  - Outside world model: consists of the four interconnected neighboring regions contiguous with the NYCA (ISO-NE, PJM, IESO, and HQ)
  - NYCA reliability is improved and IRM requirements can be reduced by recognizing available EA from the neighboring interconnected control areas
  - For the 2023 IRM Study, two outside world areas, New England and PJM, were each represented as multi-area models
  - Need to recognize internal transmission constraints within those areas that may limit EA into the NYCA
  - This recognition is considered through direct multi-area modeling of well-defined outside world area (“bubbles”) and their internal interface constraints (“pipes”)
  - The 2023 IRM study continues to limit the EA assistance to a maximum of 3,500 MW as applied in the previous five IRM Studies
  - EA is calculated annually
- While the EA to Peak Load ratio is unavailable, for the previous seven IRM studies, EA has reduced IRM requirements in the range of 6.9 to 8.7%

NYISO: Recent Developments

- A new EA model is being proposed that takes the neighboring region's weather into consideration
- New EA Methodology:
  - The *headroom method* estimates the EA available from each neighbor's capacity limit according to the weather conditions
  - In the simulations, GE MARS draws a flow amount from each neighboring region according to the severity of the weather in that region
  - The EA amount is an input to the IRM GE MARS model that ultimately decreases the required IRM
  - The EA calculation is performed yearly, but the adjustment is made only if the year-to-year difference is greater than 25 MW
- EA to Peak Load ratio for new methodology: 7.7%

PJM: Overview

- Capacity market:
  - Reliability Pricing Model (auction three years ahead of delivery year)
- Neighbors are NYISO to the north, MISO to the west, TVA to southwest, and VACAR (NERC Virginia, Carolinas region) to the south

Fast Facts

- **Service territory:** 369,089 square miles
- **Power plants:** 1,379
- **Miles of transmission:** 84,236
- **Peak demand (2019):** 148,228 MW

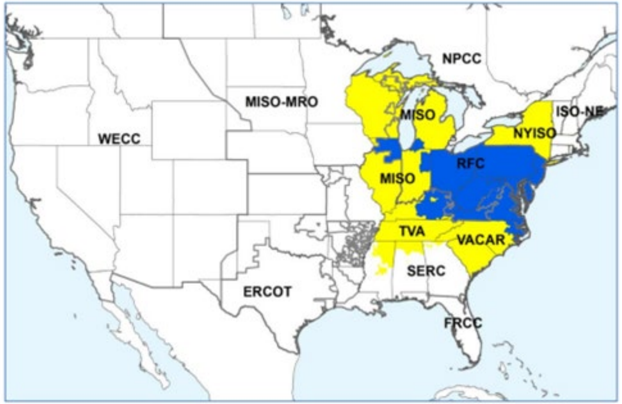
PJM: Resource Adequacy

- PJM conducts the annual Reserve Requirement Study (RRS) to satisfy the NERC/ReliabilityFirst (RF) Planning Resource Adequacy Standard
- Criteria: maximum LOLE of one occurrence in ten years
- Results of the study are both the Installed Reserve Margin (IRM, a measure of the installed capacity) and the Forecast Pool Requirement (FPR, a measure of the unforced capacity)
- Software: PJM’s Probabilistic Reliability Index Study Model (PRISM) program is the primary reliability modeling tool used in the RRS

PJM: Tie Benefits Methodology

- Terminology: capacity benefit of ties (CBOT)
- Outside world model: Area 1 (blue) - the PJM RTO and Area 2 (yellow) - the neighboring world
- Methodology:
  - CBOT is a measure of the reliability value that world interface ties bring into the PJM RTO
  - CBOT is calculated yearly in the RRS
  - The capacity benefit margin (CBM) is the amount of import capability that is reserved for emergency imports into PJM
  - The CBOT is directly affected by the PJM/world load diversity in the model (more diversity results in a higher CBOT) and the availability of assistance in the world area
  - Firm capacity imports, which are treated as internal capacity, are not part of the CBOT
  - The CBOT is a mathematical expectation related to the total CBM value
    - The expected value is the weighted mean of the possible values, using their probability of occurrence as the weighting factor
- CBOT to Peak Load Ratio: ~1%

PJM RTO, World and Non-Modeled Regions (PJM Region in blue)



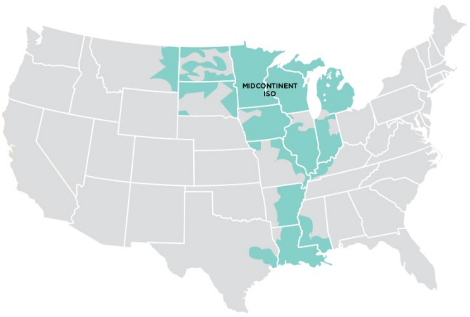
PJM: Recent Developments

- In the wake of winter storm Elliott, PJM launched the Critical Issue Fast Path Resource Adequacy (CIFP-RA) accelerated stakeholder process mechanism
- Among the proposals in the CIFP-RA (Proposed Modifications to Sustainable Capacity Market Design, July 17, 2023) are the Key Work Activity 2 - Reliability Risks and Drivers, which includes:
  - Emergency Imports - Independent Market Monitor Proposal: Capacity benefit of ties reevaluated
  - CIFP Modification to IMM Proposal: Elimination of CBOT
- In September 2023, the PJM Board has directed PJM to maintain the status quo provisions in the Reliability Assurance Agreement (RAA) regarding the consideration of CBOT in the determination of IRM
  - The PJM Board believes more discussion on this topic is necessary prior to supporting a singular value of 0 MW

MISO: Overview

- Capacity market:
  - MISO does not have a mandatory capacity market because all states but Illinois have vertical utilities with regulated electricity rates
  - MISO maintains an annual capacity requirement on all LSEs based on the load forecast plus reserves
  - This capacity can be acquired either through an annual (non-mandatory) capacity auction (the Planning Resource Auction, or PRA), bilateral purchase, or self-supply
  - The PRA is a voluntary auction for acquiring capacity resources for the following year
- Neighbors are PJM to the east, and ERCOT & SPP to the west

Fast Facts



- **Service territory:** 900,000 square miles
- **Generating units:** 6,500+
- **Miles of transmission:** 66,000
- **Peak demand (2018):** 121,563 MW

MISO: Resource Adequacy

- MISO conducts an annual LOLE study to determine a Planning Reserve Margin (PRM) for each season of the upcoming year
- Criterion: the LOLE study determines a minimum PRM for each season that would result in the MISO system experiencing a less than one-day loss of load event every 10 years
- Software: Astrapé's Strategic Energy Risk Valuation Model (SERVM) software

MISO: Tie Benefits Methodology

- Terminology: non-firm external support
- Methodology (2015-2022)
  - From 2015 to 2022, non-firm external support was assigned a constant value
  - In this method, a hypothetical 1 MW increase of non-firm support from external areas would lead to a 1 MW decrease in the reserve margin
- New methodology (2023)
  - The static non-firm external support value has now changed for 2023-2024
  - Non-firm imports in the Planning Year 2023-2024 LOLE study were modeled as a probability distribution based on historical values
  - Outside world model: an additional region was included in SERVM containing 12,000 MW of perfect generation connected to the MISO system
  - The new non-firm emergency imports are now updated yearly
- Non-firm external support to peak load ratio: 3.8%

MISO: Tie Benefits Methodology, cont.

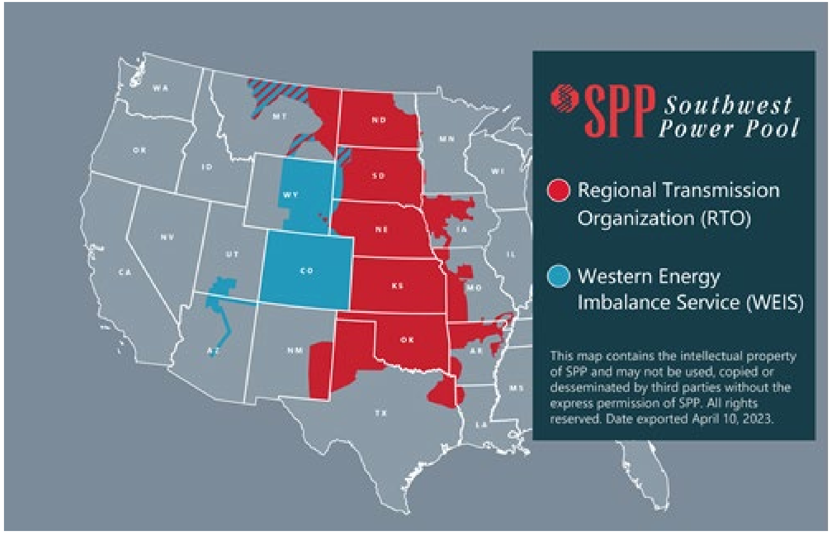
- New methodology (2023), cont.
  - As the model steps through the hourly simulation, random draws on the export limits of the external region are used to represent the amount of capacity MISO could import to meet peak demand
  - The probability distribution of non-firm external imports used in the LOLE model is exemplified in the table below
  - Non-firm support is now included as a direct input into the model rather than a post-modeling reduction in requirements
  - Non-firm support being included in the model resulted in a decrease to the PRM values

	Summer	Fall	Winter	Spring
P(X<___) = 0.05	1,456	649	-	1,777
P(X<___) = 0.10	2,663	1,259	205	2,144
P(X<___) = 0.25	3,674	2,199	1,142	2,768
P(X<___) = 0.50	4,708	3,393	3,143	4,031
P(X<___) = 0.75	5,608	4,537	4,941	5,265
P(X<___) = 0.90	6,465	5,453	7,249	6,271
P(X<___) = 0.95	6,807	6,217	8,452	7,055

SPP: Overview

- Capacity market:
  - Unlike the RTOs in the east, and much like MISO, SPP does not operate a mandatory capacity market
- Note: nearly all states within SPP regulate their electric utilities as vertically integrated, and therefore the states are primarily responsible for maintaining resource adequacy
- SPP also operates the Western Energy Imbalance Service Market (WEIS)
- SPP's WEIS balances generation and load regionally and in real time for participants in the Western Interconnection
- Utilities do not have to be a member of the SPP RTO to participate

Fast Facts



- **Service territory:** 546,000 square miles
- **Power plants:** 818
- **Miles of transmission:** 68,272
- **Peak demand (2019):** 50,622 MW

SPP: Resource Adequacy

- SPP performs a biennial LOLE study
- Determination of the SPP Planning Reserve Margin (PRM) is supported by the probabilistic LOLE Study
- Criterion: SPP determines the PRM such that the LOLE for the applicable planning year does not exceed one day in ten years, or 0.1 days per year
- Software: Astrapé’s SERVM

SPP: Tie Benefits Methodology

- Terminology: non-firm assistance
- SPP does not include any external non-firm assistance from external entities in the determination of its PRM
- Also, the load-serving entities are required to only qualify firm capacity, meaning they cannot claim external non-firm capacity to meet their obligations under the SPP Tariff

ERCOT: Overview

- Capacity market:
  - ERCOT operates an energy-only market
- ERCOT is not under FERC’s jurisdiction
- The Public Utility Commission of Texas (PUCT) regulates ERCOT, with oversight from the Governor and the Texas Legislature

Fast Facts

- **Service territory:** 201,450 square miles
- **Generating units:** 1,100
- **Miles of transmission:** 52,700
- **Peak Demand:** 85,435 MW (August 10, 2023)

ERCOT: Resource Adequacy

- ERCOT calculates a seasonal Planned Reserve Margin (PRM) similarly to other ISOs:
  - PRM = Total Resources / (Adjusted Peak Demand – Emergency Resources) - 1
- The way to ensure resource adequacy is to establish a minimum criterion for the PRM
- Criterion: the minimum ERCOT PRM is approved by the ERCOT Board
  - Currently it is at 13.75%
- ERCOT periodically reviews and recommends to the ERCOT Board any changes to the minimum ERCOT PRM to help ensure adequate reliability of the ERCOT System
- Unlike the ISOs previously discussed, ERCOT does not use a probabilistic approach to resource adequacy
  - Clearing a PRM is a deterministic (accounting) approach
- Software: Does not require any specialized software

ERCOT: Tie Benefits Methodology

- Terminology: DC tie capacity available under emergency conditions (DCTIECAP)
- Methodology:
  - The amount of expected existing DC tie capacity available under emergency conditions, DCTIECAP, is included in the Total Resources (numerator in the PRM equation)
  - This means that the amount of internal capacity required to achieve the required PRM is reduced by the DCTIECAP
  - The DCTIECAP is limited to the most recent single summer and winter seasons in which an energy emergency alert (EEA) was declared
- DCTIECAP to Peak Load ratio: ~1.5%

ERCOT: Recent Developments

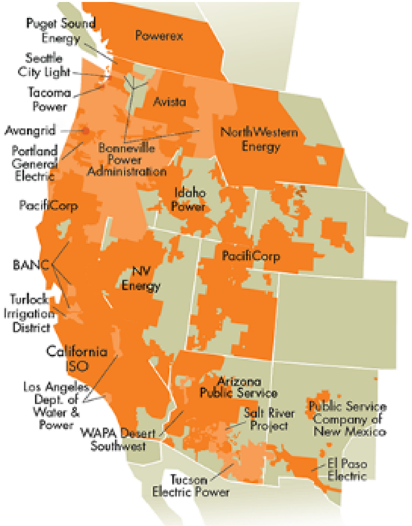
- Following soon after the Winter Storm Uri in February 2021, Senate Bill 3 mandated the creation of an updated ERCOT Reliability Standard by the PUC of Texas
- ERCOT recommended a standard defined by a three-part framework consisting of the following limits:
  - Maximum magnitude of any single loss of load event
  - Maximum frequency of loss of load events
  - Maximum duration of any single loss of load events
- ERCOT is running an analysis of the above framework using probabilistic Monte Carlo simulations on SERVM

CAISO: Overview

- Capacity market:
  - No formal capacity market
- In addition to operating the energy market in California, CAISO also operates the Western Energy Imbalance Market (WEIM), which is a real-time regional power trading market

Fast Facts

- **Service territory:** 132,000 square miles
- **Generating units:** 1,019
- **Miles of transmission:** 26,000
- **Peak demand (2019):** 44,301 MW



CAISO: Resource Adequacy

- While CAISO does not operate a formal capacity market, it does have a mandatory resource adequacy requirement, which is based on the California Public Utility Commission's (CPUC) resource adequacy framework
- Criterion: the program requires that LSEs procure 115% of their aggregate system load on a monthly basis
- This is similar to ERCOT's resource adequacy approach, *i.e.,* not a probabilistic approach, but a deterministic one
- Software: no specialized software is needed

CAISO: Tie Benefits Methodology

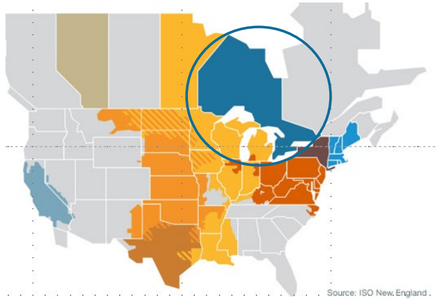
- Terminology: non-firm external support
- CPUC, having jurisdiction over the vast majority of CAISO LSEs, does not allow non-firm external support to count towards LSEs' system resource adequacy requirements

IESO: Overview

- Capacity market:
  - Annual capacity auction
  - Resources compete to be available for two six-month obligation periods (summer and winter)

Fast Facts

- **Installed capacity**: 38,000 MW
- **Record Summer Peak**: 27,000 MW (2006)
- **Population Covered**: 5.3 million
- **Miles of transmission**: 18,600



IESO: Resource Adequacy

- IESO employs three types of adequacy assessments:
  - Annual long-term **capacity** assessments looking forward 5 years or more
    - This is a multi-area probabilistic reliability assessment using GE MARS that determines how much capacity is needed to achieve an LOLE of 0.1 days/year
  - Criterion: uses NPCC Directory #1 requirement of LOLE = 0.1 days/year
  - Annual long term **energy** adequacy assessments looking forward 5 years or more
    - This is a deterministic production-cost model using UPLAN/PLEXOS to determine whether IESO will be able to serve energy in the future
    - It also optimizes for cost minimization and emissions reduction
    - The main metrics are unserved energy and surplus baseload generation
  - 18-month Reliability Outlook
    - Implementation in PLEXOS of a probabilistic load & capacity model, using direct convolution, the output of which is the required reserve
    - An resource adequacy criterion equivalent to a LOLE of 0.1 days/year is used to determine the probabilistic reserve requirement for each week of the planning year

IESO: External Assistance Methodology

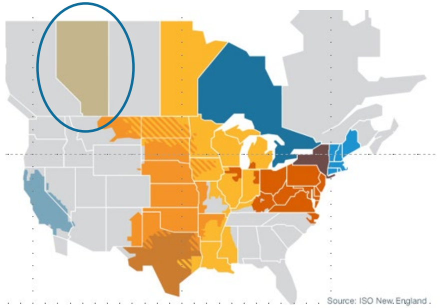
- In 2021, the IESO started to include non-firm imports in the IESO's resource adequacy assessments to further align with NPCC criteria
- Methodology:
  - The selected approach was to look at the previous 5 years, and determine the 90^{th} percentile dependable flow in the top 5% of Hourly Ontario Energy Price (HOEP) hours
  - This amounted to approximately 250 MW (across all ties)
- Non-firm emergency imports to Peak Load ratio: 0.92%

AESO: Overview

- Capacity market:
  - The wholesale electricity market in Alberta is currently **energy-only**

Fast Facts

- **Installed capacity**: 18,344 MW
- **Record Winter Peak**: 12,193 MW (2022)
- **Population Covered**: 4.0 million
- **Miles of transmission**: 16,100



Source: ISO New England.

AESO: Resource Adequacy

- The Two Year Probability of Supply Adequacy Shortfall (PSAS) metric is a probabilistic assessment of encountering a supply shortfall over the next two years
- The PSAS is the equivalent of expected unserved energy (EUE)
  - It builds on the supply cushion metric (reserve margin) by incorporating the probability of wind production, forced generation outages, and generation de-rates into the calculation of hourly firm supply
- Criterion: PSAS ≤ 2,000 MWh
- Software: Astrapé's SERVM

AESO: Tie Benefits Methodology

- Terminology: AESO does account for *external non-firm emergency support* from interconnections with regards to resource adequacy requirements

- Methodology:
  - It's not represented within the reserve margin calculations, but is within the PSAS
  - The contribution of the intertie is included in AESO's analysis and does has the effect to reduce the need for internal capacity
  - AESO has a couple of ways in which the external non-firm emergency support is calculated
    - In the simple way, they include a pro-rated value of total transmission capacity (TTC)
    - For the more rigorous representation, similarly to MISO, they have a distribution of intertie availability that the probabilistic model draws from

Summary Table (1/3)

ISO/ RTO	Capacity Market	Resource Adequacy	Considers tie benefits? Frequency of Update? Tie benefits methodology Tie benefits to peak load ratio
NYISO	Installed Capacity Market (ICAP): Prompt (seasonal and monthly)	• Criteria: LOLE = 0.1 days/year • Analysis: Multi-area, probabilistic • Software: GE MARS	• Yes, annually in the IRM • Emergency Assistance is based on weather dependent historical values that are inputs into the GE MARS model and that ultimately decrease the IRM • 7.7% of peak load
PJM	Forward (3-year)	• Criteria: LOLE = 0.1 events/year • Analysis: Multi-area, probabilistic • Software: PRISM	• Yes, annually in the RRS • Capacity Benefits of Ties (CBOT) is a measure of the reliability that world interface brings into the PJM. The output is the mathematical expectation of the import capability, using its known probability distribution • 1% of peak load
MISO	PRA: Voluntary auction for acquiring capacity for the following year	• Criteria: LOLE = 1 event / 10 years • Analysis: Probabilistic • Software: SERVM	• Yes, annually for PRA • Initially, from 2015 to 2022 was assigned a constant value. Since 2023, non-firm imports were modeled as a probability distribution based on historical values. An additional outside world region was included in the SERVM LOLE model connected to MISO, carrying perfect generation according to this probability distribution • 3.8% of peak load

Summary Table (2/3)

ISO/RTO	Capacity Market	Resource Adequacy	Considers tie benefits? Frequency of Update? Tie benefits methodology Tie benefits to peak load ratio
ERCOT	Energy-only	• Criteria: The minimum ERCOT Planned Reserve Margin (PRM) criterion is approved by the ERCOT Board. *PRM = Total Resources /(Adjusted Peak Demand – Emergency Resources)-1* • Currently, PRM is set to 13.75% • Analysis: deterministic • Software: N/A	• Yes, only when an EEA is declared • *DCTIECAP*, the DC tie capacity available under emergency conditions, is included in the *Total Resources*, reducing the amount of internal capacity required to meet the PRM • 1.5% of peak load
AESO	Energy-only	• Criteria: Expected Unserved Energy, EUE (called Probability of Supply Adequacy Shortfall, PSAS) ≤ 2,000 MWh • Analysis: Probabilistic • Software: Strategic Energy Risk Valuation Model (SERVM)	• Yes, Unknown • Similar to MISO, the external non-firm support is modeled in SERVM as a distribution of intertie availability the model draws from. Does have the effect of reducing internal required capacity • Tie benefits to peak load ratio: Unknown
IESO	Annual Capacity Auction: Two seasonal six-month obligation periods (winter and summer)	• Criteria: Annual long-term GE MARS capacity adequacy assessment using a criterion of LOLE = 0.1 days per year • Analysis: Annual deterministic cost-minimizing long-term energy adequacy assessment using PLEXOS • Software: 18-month reliability outlook using PLEXOS/direct convolution	• Yes, Unknown • Beginning in 2021, non-firm imports modeled by considering previous 5 years and determining the 90^{th} percentile of dependable flow in the top 5% of Hourly Ontario energy Price (HOEP) hours. This amounted to 250 MW across all ties • Tie benefits to peak load ratio: 0.92% of peak load

Summary Table (3/3)

ISO/RTO	Capacity Market	Resource Adequacy	Considers tie benefits? Frequency of Update? Tie benefits methodology Tie benefits to peak load ratio
SPP	No formal capacity market	• Criteria: LOLE = 0.1 day/year • Analysis: Probabilistic • Software: SERVM	• No, N/A • Methodology: N/A • Tie benefits to peak load ratio: N/A
CAISO	No formal capacity market	• Criteria: Requires that LSEs procure 115% of the aggregate system load on a monthly basis • Analysis: Deterministic • Software: N/A	• No, N/A • Methodology: N/A • Tie benefits to peak load ratio: N/A
ISO-NE	• The Forward Capacity Market • The FCA is held annually, three years in advance of the Capacity Commitment Period (CCP)	• Criteria: LOLE = 0.1 day/year • Analysis: Probabilistic • Software: GE MARS	• Yes, annually for FCA and ARA 3 of each CCP • Tie benefits shall be calculated using a probabilistic multi-area reliability model, by comparing the LOLE for the New England system before and after interconnecting the system to the neighboring Control Areas. To quantify tie benefits, firm capacity equivalents shall be added until the LOLE of the isolated New England Control Area is equal to the LOLE of the interconnected New England Control Area. The added firm capacity is the amount of tie benefits • 7.5% of peak load

NEXT STEPS FOR ISO-NE TIE BENEFITS METHODOLOGY EVALUATION

What does the ISO plan to review?
What is the schedule to present key findings and any recommendations?

Tie Benefits Methodology Evaluation - Scope

- The ISO plans to review the following topic areas of tie benefits:
  - Historical review of external transfers
    - What were flows during stressed times on the system?
  - Future outlook for the northeast
    - Qualitative analysis for future load/resource diversity and interregional transfers
  - Modeling assumptions review
    - What are the salient features of the current model?
    - Where can the model be improved?

Tie Benefits Methodology Evaluation - Schedule

- Additional PSPC meetings outside the usual ICR and related values planning cycle have been scheduled to discuss this topic
  - January 25, 2024
  - March 15, 2024
- The regular PSPC cycle for 2024 will start in May 2024
  - Additional PSPC time will be dedicated for this topic
- The goal is to present ISO-NE's key findings and any recommendations from the analysis by September

Questions