

June 9, 2026

VIA ELECTRONIC MAIL

TO: MEMBERS AND ALTERNATES OF THE NEPOOL PARTICIPANTS COMMITTEE

RE: Supplemental Notice of June 16–18, 2026 NEPOOL Participants Committee Summer Meeting

Pursuant to Section 6.6 of the Second Restated New England Power Pool Agreement, supplemental notice is hereby given that the NEPOOL Participants Committee Summer Meeting will be held on June 16–18, 2026 at Newport Harbor Island (NHI) on Goat Island in Newport, RI. Please see the attached Summer Meeting agenda, which is also posted with the meeting materials.

As reflected on the meeting agenda:

- **Tuesday (Jun 16):** General NEPOOL business will be conducted on Tuesday, with a planned **9:30 a.m. start**. Note that Tuesday's agenda includes the annual markets presentation by the ISO's External Market Monitor (EMM).
- **Wednesday (Jun 17):** Wednesday morning has been set aside for a presentation by the ISO's Internal Market Monitor (IMM) of (i) the 2025 IMM Annual Markets Report and (ii) an Assessment of the Day-Ahead Ancillary Services Market.
- **Thursday (Jun 18):** On Thursday, modified Sector group meetings are scheduled to begin at 8:30 a.m., with times set aside for each group to meet separately with ISO Board members, State Officials, and FERC representatives. ***Please note when and where your modified Sector group is scheduled to meet.***

We understand that everyone planning to attend the Summer Meeting in person is registered for the meeting. If you cannot make the meeting in person, the June 16 and June 17 plenary sessions will be accessible by Webex for those who otherwise attend NEPOOL meetings, and approved guests. To join via Webex, click this [link](#) and enter the event password **nepool**.

The NEPOOL reservations block at NHI is full. If you have a need for overnight accommodations, please contact Laura Clark (llark@daypitney.com), who may be able to assist you with alternative arrangements. For those staying at NHI, please note that **the cancellation policy is at least 7 days prior to the first day of your reservation. If any of your arrangements have changed, including the number of people you registered, please contact Laura as soon as possible.**

Dress for the Summer Meeting is business casual. Additional information regarding the Summer Meeting is available on the [Summer Meeting information page](#).

We very much look forward to seeing you in Newport.

Respectfully yours,

/s/
Sebastian Lombardi, Secretary

FINAL AGENDA

TUESDAY, JUNE 16, 2026

9:30 a.m. – 4:30 p.m. General Session
(Beacon Ballroom)**

1. To approve the draft minutes of the Participants Committee meetings held on April 30 and May 7, 2026. A copy of each set of draft minutes is included and posted with this supplemental notice. Please provide us with any comments on the draft minutes **on or before 5:00 p.m., Thursday, June 11, 2026**.
2. To adopt and approve all actions recommended by the Technical Committees set forth on the Consent Agenda included with this supplemental notice and posted with the meeting materials. Consent Agenda Item No. 1 has been removed and will be considered as Item 10A (*see below*).
3. To receive remarks from Vamsi Chadalavada, Chief Executive Officer, ISO New England. A summary of the ISO Board and Board Committee meetings held since the last Participants Committee meeting is included with this supplemental notice and posted with the meeting materials.
4. To receive a Systems and Market Operations Report. The ISO's June Systems and Market Operations Report, reflecting May data, will be circulated and posted in advance of the meeting.
5. To receive a report on the ISO's preliminary 2027 and 2028 Operating and Capital Budgets by Kelly Reyngold, Chief Financial Officer, ISO New England. The 2027 Budget Presentation is included with this supplemental notice and posted with the meeting materials.
6. To consider and take action, as appropriate, on changes to Section IV.A and Section IV.B of the Tariff to clarify how the ISO's annual rates, charges, and capital budget (together, the Calendar Year Rates) will be administered if, by January 1, those Calendar Year Rates have not been authorized by the FERC or have not otherwise become effective. Background materials and a draft resolution are included with this supplemental notice and posted with the meeting materials.
7. To consider and take action, as appropriate, on changes to the Pay-For-Performance (PFP) treatment of external transactions during Capacity Scarcity Conditions and settlement calculations, and related revisions to Tariff Sections I, III, the Billing Policy, and the Financial Assurance Policy (FAP). Background materials and draft resolutions are included with this supplemental notice and posted with the meeting materials.

* The NEPOOL general business portions and plenary sessions of the meeting will be recorded, as are all the NEPOOL Participants Committee meetings. NEPOOL meetings, while not public, are open to all NEPOOL Participants, their authorized representatives and, except as otherwise limited for discussions in executive session, consumer advocates that are not members, federal and state officials and guests whose attendance has been cleared with the Committee Chair. All those participating in this meeting must identify themselves and their affiliation at the meeting. Official records and minutes of meetings are posted publicly. No statements made in NEPOOL meetings are to be quoted or published publicly.

****All start and finish times subject to adjustment.**

8. To consider and take action, as appropriate, on changes to cap the PFP Capacity Balancing Ratio at 1.0 and to make related revisions to Tariff Sections I, III, and the FAP. Background materials and draft resolutions are included with this supplemental notice and posted with the meeting materials.
9. To consider and take action, as appropriate, on the ISO's proposed downward adjustment to the Performance Payment Rate (PPR) and related revisions to Sections III.13.7 and III.15. Background materials, including information on a potential amendment and a request for further assessment of the proposed PPR adjustment, are included with this supplemental notice and posted with the meeting materials.
10. To consider and take action, as appropriate, on Day-Ahead Ancillary Services (DAAS) post-implementation market adjustments in response to recommendations by the Internal Market Monitor (IMM). Background materials and a draft resolution are included with this supplemental notice and posted with the meeting materials.
- 10A. To consider and take action, as appropriate, on changes to the NEPOOL Generation Information System (GIS) and GIS Operating Rules related to marking of Certificates as being transferred under Section 83D of the Massachusetts Act Relative to Green Communities. This item was removed from the Consent Agenda (Consent Agenda Item 1). Background materials, including a memo from Participant representatives proposing to amend the draft resolution to approve the changes, are included with this supplemental notice and posted with the meeting materials.
11. To receive a report on current matters relating to regional wholesale power and transmission arrangements that are pending before the regulators and the courts.
12. To receive reports from other Committees, Subcommittees, and working groups:
 - Markets Committee
 - Reliability Committee
 - Transmission Committee
 - Budget & Finance Subcommittee
 - Membership Subcommittee
 - Others
13. FERC Staff Introductions.
14. To receive an External Market Monitor Report by Dr. David Patton, President, Potomac Economics. A presentation with highlights of the EMM's 2025 Annual Assessment of the ISO New England Electricity Markets will be circulated and posted following receipt.
15. To transact such other business as may properly come before the meeting.

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WEDNESDAY, JUNE 17, 2026

9:30 a.m. – 12:00 p.m.**

(Beacon Ballroom)

16. To receive welcoming remarks from a state official(s) of the State of Rhode Island.
17. To receive an IMM Report from David Naughton, Executive Director, Market Monitoring, including highlights from the IMM's:
 - 2025 Annual Markets Report; and
 - Day-Ahead Ancillary Services Market Assessment.

A copy of the IMM's 2025 Annual Markets Report is included and posted with the composite materials for the meeting. The Day-Ahead Ancillary Services Assessment is included with this supplemental notice and posted with the meeting materials. Further material will be circulated and posted in advance of the meeting.

*Wednesday afternoon has been set aside for
separate meetings and organized networking, as desired.*

THURSDAY, JUNE 18, 2026

8:30 a.m. – 12:45 p.m.**

*Thursday, June 18 has been set aside for
separate, modified Sector meetings with ISO Board Members,
State Officials, and FERC Representatives,
as detailed in the Sector meeting schedule included with this agenda.*

* The NEPOOL general business portions and plenary sessions of the meeting will be recorded, as are all the NEPOOL Participants Committee meetings. NEPOOL meetings, while not public, are open to all NEPOOL Participants, their authorized representatives and, except as otherwise limited for discussions in executive session, consumer advocates that are not members, federal and state officials and guests whose attendance has been cleared with the Committee Chair. All those participating in this meeting must identify themselves and their affiliation at the meeting. Official records and minutes of meetings are posted publicly. No statements made in NEPOOL meetings are to be quoted or published publicly.

****All start and finish times subject to adjustment.**

**23rd Annual
Participants Committee Summer Meeting
Newport, RI
June 18, 2026 Schedule**

JUN 9, 2026 DRAFT

SECTOR/GROUP	8:30–9:45 a.m.	10:00–11:15 a.m.	11:30 a.m.–12:45 p.m.	11:45 a.m.–2:00 p.m.
Generation / Long	State Officials Panel 1 <i>(Beacon D)</i>	ISO Board Panel 2 <i>(Beacon A)</i>	FERC Staff (12:15–12:45) <i>(Hamilton)</i>	Lunch (All) <i>Rose Island Ballroom</i>
Transmission	State Officials Panel 2 <i>(Beacon B)</i>	ISO Board Panel 1 <i>(Beacon C)</i>	FERC Staff (11:30–12:00) <i>(Hamilton)</i>	
Supplier / Short (LSE)	ISO Board Panel 1 <i>(Beacon C)</i>	FERC Staff (10:45–11:15) <i>(Hamilton)</i>	State Officials Panel 1 <i>(Beacon D)</i>	
Publicly Owned Entity	FERC Staff (8:30–9:00) <i>(Hamilton)</i>	State Officials Panel 2 <i>(Beacon B)</i>	ISO Board Panel 1 <i>(Beacon C)</i>	
AR	FERC Staff (9:15–9:45) <i>(Hamilton)</i>	State Officials Panel 1 <i>(Beacon D)</i>	ISO Board Panel 2 <i>(Beacon A)</i>	
End User	ISO Board Panel 2 <i>(Beacon A)</i>	FERC Staff (10:00–10:30) <i>(Hamilton)</i>	State Officials Panel 2 <i>(Beacon B)</i>	
ISO Board Panel 1	Supplier / Short (LSE) <i>(Beacon C)</i>	Transmission <i>(Beacon C)</i>	Publicly Owned Entity <i>(Beacon C)</i>	
ISO Board Panel 2	End User <i>(Beacon A)</i>	Generation / Long <i>(Beacon A)</i>	AR <i>(Beacon A)</i>	
State Officials Panel 1	Generation / Long <i>(Beacon D)</i>	AR <i>(Beacon D)</i>	Supplier / Short (LSE) <i>(Beacon D)</i>	
State Officials Panel 2	Transmission <i>(Beacon B)</i>	Publicly Owned Entity <i>(Beacon B)</i>	End User <i>(Beacon B)</i>	
FERC Staff	Publicly Owned (8:30–9:00) AR (9:15–9:45) <i>(Hamilton)</i>	End User (10:00–10:30) Supplier/Short (LSE) (10:45–11:15) <i>(Hamilton)</i>	Transmission (11:30–12:00) Generation/Long (12:15–12:45) <i>(Hamilton)</i>	

ISO Board Panel 1: Caren Anders, Mike Curran, Craig Ivey, Cheryl LaFleur, Mark Vannoy

ISO Board Panel 2: Brook Colangelo, Steve Corneli, Catherine Flax, Mel Williams, and Vamsi Chadalavada

State Officials Panel 1: RI PUC Commissioner Karen Bradbury, RI PUC Staff Todd Bianco, CT PURA Chairman Thomas Wiehl, CT DEEP Deputy Commr. Andy Frank, CT DEEP Staff Eric Annes, ME PUC Commr. Patrick Scully, ME DOER Staff Bob Snook, MA DPU Commr. Liz Anderson, MA EEA Asst. Secretary Austin Dawson, NH PUC Commr. Mark Dell'Orfano (virtual), NH DOE Staff Bruce Blair, NH DOE Staff Dan Phelan, VT PUC Chair Ed McNamara, NESCOE Staff Jeff Bentz, NESCOE Staff Shannon Beale, and NECPUC Exec. Dir. George Twigg

State Officials Panel 2: RI PUC Chairman Ron Gerwatoski, CT DEEP Staff Josh Walters, ME PUC Chair Phil Bartlett, ME DOER Staff Celina Cunningham, ME PUC Staff Michael Haskell, MA DPU Chair Jeremy McDiarmid, MA EEA Assistant Secretary Weezie Nuara, MA DPU Staff Gregg Wade, NH PUC Chairman Chris Ellms (virtual), NH DOE Staff Matt Young, VT DPS Commissioner Kerrick Johnson, NESCOE Staff Sheila Keane, NESCOE Staff Nathan Forster, and NESCOE Exec. Dir. Heather Hunt

FERC Staff: Eric Jacobi, Noah Schlosser, and Aaron Siskind

PRELIMINARY

Pursuant to notice duly given, a special Webex meeting of the NEPOOL Participants Committee was held beginning at 9:00 a.m. on Thursday, April 30, 2026. A quorum, determined in accordance with the Second Restated NEPOOL Agreement, was present and acting throughout the meeting. Attachment 1 identifies the members, alternates, and temporary alternates who participated in the meeting.

Ms. Sarah Bresolin, Chair, presided, and Mr. Sebastian Lombardi, Secretary, recorded. Ms. Bresolin welcomed the members, alternates and guests who were present.

PURPOSE OF SPECIAL MEETING

Ms. Bresolin welcomed the Committee to the special meeting that was being held, at the request of a number of Transmission Sector members, to consider and take action on proposed revisions to Attachment F (Appendix A, Worksheet 2) to Section II of the ISO Tariff (Attachment F Revisions), including a proposed new region-wide base return on equity (ROE). She referred members to the background materials circulated in advance of the meeting and posted to the NEPOOL website. Ms. Bresolin explained that the Participating Transmission Owners Administrative Committee (PTO-AC) planned to file later that day on behalf of the Participating Transmission Owners (PTOs) a prospective new ROE (a proposed change to the 9.57% ROE that had been directed by the FERC in its March 19, 2026 Opinion No. 594 (*Opinion 594*)) and was seeking Participants Committee action ahead of that filing. Ms. Bresolin noted for the Committee that the specific ROE % to be proposed in the PTO-AC filing would be identified and included in the motion to support the Attachment F Revisions before that motion was moved. She further indicated that a motion to amend the ROE % was expected to be offered by a Market Participant End User representative.

PTO-AC ROE PROPOSAL

Mr. Nick Gangi, Transmission Committee (TC) Chair, summarized the Participant Processes undertaken to that point. Mr. Gangi explained that, at the April 21, 2026 TC, the PTO-AC had proposed a revision to Attachment F in response to *Opinion 594*. While the revisions struck the 10.57% base ROE rate in the Tariff, no new % was identified at that time; instead the PTO-AC inserted a placeholder for a new base ROE rate to be filled in later, and as part of the PTO-AC's FERC filing. Ultimately, at the April 21 TC meeting, and based on a roll call vote, the TC did not recommend Participants Committee support for the PTO-AC proposal, with a 19.84% vote in favor (that percentage registered by the Transmission Sector reflected an upward adjustment to the Sector voting share based on the lack of Sector Quorum achieved by the Alternative Resources (AR) Sector at the TC meeting).

Ms. Bresolin then introduced and invited Ms. Jackie Hansen, a PTO-AC representative, to make brief remarks on the Attachment F Revisions. Ms. Hansen thanked the Committee for accommodating the PTO's request for the special meeting, and explained that the PTO-AC would make a filing, under Section 205 of the Federal Power Act, following the meeting that day, to revise the going forward region-wide base ROE to reflect, in their view, current economic conditions for transmission assets included in Attachment F. She noted that the 9.57% base ROE established in *Opinion 594* was based on market data from October 2012 and explained that the PTO-AC filing would propose a new base ROE of 11.39%, employing the same methodology as used by the FERC in *Opinion 594* but reflecting current economic conditions. The contemplated effective date for this newly proposed base ROE would be June 30, 2026.

Members then asked clarifying questions. In response to questions regarding when any new ROE might be reflected in rates, Ms. Hansen said that the PTOs' annual 2027 rate filing

would not initially reflect any change from the FERC-directed 9.57% ROE. However, if the new ROE was accepted, the PTOs were not in a position at this meeting to identify how or when the new ROE would then in turn be reflected in rates. The PTO-AC did not have plans to submit additional redlines, other than to insert the 11.39%, and did not believe that the new percentage would be changed based on discussion at the meeting. Ms. Hansen confirmed that the going-forward ROE would be evaluated on its own merits and would not in and of itself impact the refund ordered in the existing ROE proceedings. She added that additional support for the 11.39% would be presented in the FERC proceeding, but not during the special meeting.

Addressing questions as to what rate applied, and by whom the rate was set, Ms. Hansen confirmed that the base ROE percentage applied to the Pool Transmission Facilities (PTF) asset rate, which an ISO representative confirmed was solely within the purview of the PTOs to set and was used as an input to the Annual Revenue Requirement. The timing of consideration of the Attachment F Revisions was similarly driven by the PTOs, who wished to have the rates be in effect as of July 1 and not push any later into that period as a result of consideration at a later, regularly-scheduled Participants Committee meeting. In response to further questions, Ms. Hansen said that the new ROE would not impact other applicable incentives or adders under the Tariff.

The following main motion was then duly made and seconded:

RESOLVED, that the Participants Committee supports the Attachment F Revisions, as proposed by the PTO-AC, together with such non-substantive changes as may be agreed to after the meeting by the Chair of the Participants Committee.

Market Participant End User Amendment

A Market Participant End User representative then made a motion to amend the main motion, which was duly seconded, so as to set the base ROE at 9.57% (reflecting the same % as directed in *Opinion 594*) in lieu of the PTO-AC's proposed 11.39% base ROE.

Those supporting the motion to amend focused on the very limited opportunity to review or discuss the PTO-AC-proposed change to the FERC-directed ROE and viewed the motion to amend the ROE to 9.57%, therefore, as an appropriate replacement for the placeholder. Others, with similar reservations as to the sufficiency of time to evaluate the End User representative's proposed alternative, indicated they would abstain on the motion to amend. Transmission Sector members noted their opposition to the motion to amend.

Without further discussion, the motion to amend was voted and was determined, by a show of hands, to have failed.

Unamended Main Motion (PTO-AC Proposal)

Members then addressed the PTO-AC Proposal (the proposed 11.39% ROE).

A member of the Publicly Owned Entity Sector, acknowledging that business conditions had changed since those conditions underlying the FERC-established ROE rate, expressed disappointment with the missed opportunity to have a conversation in good faith and potentially reach consensus on a new base ROE rate. He encouraged the TOs to look for opportunities to engage in collaborative discussion.

Others expressed concern with considering and voting on a proposal with minimal notice and information. Echoing those sentiments, a NESCOE representative noted that the PTO-AC's request for stakeholders to form an opinion and vote on an ROE proposal that lacked specificity could undermine the FERC's respect for the region's decision-making predicated on a strong and

respectful stakeholder process. She added that, although NESCOE does not participate in NEPOOL voting, it objected to the PTO-AC's request for an advisory vote on what had been a blank proposal until just minutes before. She stated that the request was particularly concerning because it would directly affect New England consumers' costs. The NESCOE representative concluded that the TC vote the prior week, in which no stakeholder other than the Transmission Owners supported the proposal, was an inevitable outcome for a proposal that was not ripe for consideration.

Following a member's request for a roll call vote, the unamended main motion, including the PTO-AC's proposed base ROE of 11.39%, was then voted and was not approved. The unamended main motion failed with a 16.67% vote in favor (Generation Sector – 0%; Transmission Sector – 16.67%; Supplier Sector – 0%; AR Sector – 0%; Publicly Owned Entity Sector – 0%; and End User Sector – 0%) (*See Attachment 2*).

There being no other business, the meeting adjourned at 9:58 am.

Respectfully submitted,

Sebastian Lombardi, Secretary

**PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN THE SPECIAL APRIL 30, 2026 WEBEX MEETING**

PARTICIPANT NAME	SECTOR/GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Acadia Center	End User	Joe LaRusso		
Advanced Energy United	Assoc. Non-Voting		Alex Lawton	
Ashburnham Municipal Light Plant	Publicly Owned Entity		Matt Ide	
AVANGRID (CMP/UI)	Transmission	Alan Trotta	Jason Rauch	
Bath Iron Works	End User			Bill Short
Belmont Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Block Island Utility District	Publicly Owned Entity	Dave Cavanaugh		
Boylston Municipal Light Department	Publicly Owned Entity		Matt Ide	
Braintree Electric Light Department	Publicly Owned Entity	Dave Cavanaugh		
Chicopee Municipal Lighting Plant	Publicly Owned Entity		Matt Ide	
Clear River Electric and Water District	Publicly Owned Entity		Dave Cavanaugh	
Concord Municipal Light Plant	Publicly Owned Entity		Dave Cavanaugh	
Connecticut Municipal Electric Energy Coop.	Publicly Owned Entity	Brian Forshaw		
Connecticut Office of Consumer Counsel	End User		Jamie Talbert-Slagle	
Conservation Law Foundation	End User	Phelps Turner		
Constellation Energy Generation (Constellation)	Supplier	Andy Gillespie		
Cross-Sound Cable Company (CSC)	Supplier			Jeff Iafrati
Danvers Electric Division	Publicly Owned Entity		Dave Cavanaugh	
Dartmouth Power Associates, L.P.	Generation	Sarah Yasutake		
Dominion Energy Generation Marketing, Inc.	Generation	Wes Walker		
Elektrisola, Inc.	End User			Bill Short
ENGIE Energy Marketing NA, Inc.	AR-RG	Sarah Bresolin		
Eversource Energy	Transmission		Dave Burnham	
FirstLight Power Management, LLC	Generation	Tom Kaslow		
Fiscal Alliance Foundation, Inc.	End User	Paul Craney		
Gabel Associates, Inc.	Supplier	Sarah Yasutake		
Galt Power, Inc.	Supplier		Jeff Iafrati	
Garland Manufacturing Company	End User			Bill Short
Generation Bridge Companies	Generation		Steve Kirk	
Georgetown Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Granite Shore Companies	Generation			Bob Stein
Green Oceans	End User		Lauren Knight	
Groton Electric Light Department	Publicly Owned Entity		Matt Ide	
Groveland Electric Light Department	Publicly Owned Entity		Dave Cavanaugh	
H.Q. Energy Services (U.S.) Inc. (HQUS)	AR-RG	Louis Guilbault	Bob Stein	
Hammond Lumber Company	End User			Bill Short
Harvard Dedicated Energy Limited	End User			Doug Hurley
High Liner Foods (USA) Inc.	End User		Bill Short	
Hingham Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Holden Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Holyoke Gas & Electric Department	Publicly Owned Entity		Matt Ide	
Hudson Light and Power Department	Publicly Owned Entity			Dave Cavanaugh
Hull Municipal Lighting Plant	Publicly Owned Entity		Matt Ide	
Icetec Energy Services, LLC	AR-LR	Doug Hurley		
Industrial Energy Consumer Group	End User		Todd Griset	
Industrial Wind Action Group	End User	Lisa Linowes		
Ipswich Municipal Light Department	Publicly Owned Entity		Matt Ide	
Lamson, Jon	End User	Jon Lamson		
Littleton (MA) Electric Light and Water Dept.	Publicly Owned Entity		Dave Cavanaugh	
Long Island Power Authority (LIPA)	Supplier		Bill Killgoar	
Maine Public Advocate's Office	End User	Drew Landry		Susan Chamberlin
Maine Skiing, Inc.	End User		Todd Griset	
Mansfield Municipal Electric Department	Publicly Owned Entity		Matt Ide	

**PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN THE SPECIAL APRIL 30, 2026 WEBEX MEETING**

PARTICIPANT NAME	SECTOR/GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Marble River, LLC	Supplier	John Brodbeck		
Marblehead Municipal Light Department	Publicly Owned Entity		Matt Ide	
Mass. Attorney General's Office (MA AG)	End User	Jackie Bihle	Jamie Donovan	
Mass. Bay Transportation Authority	Publicly Owned Entity		Dave Cavanaugh	
Mass. Municipal Wholesale Electric Company	Publicly Owned Entity	Matt Ide		
MDC – The (CT) Metropolitan District	Publicly Owned Entity		Dave Cavanaugh	
Merrimac Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Midcoast Regional Redevelopment Authority	Publicly Owned Entity		Dave Cavanaugh	
Middleborough Gas & Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Middleton Municipal Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Moore Company	End User			Bill Short
New England Power (d/b/a National Grid)	Transmission	Tim Brennan	Tim Martin	
New England Power Gens. Assoc. (NEPGA)	Assoc. Non-Voting	Bruce Anderson		
New Hampshire Electric Cooperative	Publicly Owned Entity			Brian Forshaw
New Hampshire Office of Consumer Advocate	End User	Matthew Fossum		
NextEra Energy Resources, LLC	Generation	Michelle Gardner		
North Attleborough Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Norwood Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
NRG Business Marketing, LLC	Supplier	Ben Griffiths		
Nylon Corporation of America	End User			Bill Short
Pawtucket Power Holding Company	Generation	Dan Allegretti		
Paxton Municipal Light Department	Publicly Owned Entity		Matt Ide	
Peabody Municipal Light Department	Publicly Owned Entity		Matt Ide	
PowerOptions, Inc.	End User			Doug Hurley
Princeton Municipal Light Department	Publicly Owned Entity		Matt Ide	
Reading Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Rhode Island Energy (Narragansett Electric Co.)	Transmission	Brian Thomson	Robin Lafayette	
Rowley Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Russell Municipal Light Dept.	Publicly Owned Entity		Matt Ide	
Saint Anselm College	End User			Bill Short
Shell Energy North America (US), L.P.	Supplier	Jeff Dannels		
Shipyard Brewing LLC	End User			Bill Short
Shrewsbury Electric & Cable Operations	Publicly Owned Entity		Matt Ide	
South Hadley Electric Light Department	Publicly Owned Entity		Matt Ide	
Sterling Municipal Electric Light Department	Publicly Owned Entity		Matt Ide	
Stowe Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Taunton Municipal Lighting Plant	Publicly Owned Entity	Nick Parrotta	Dave Cavanaugh	
Templeton Municipal Lighting Plant	Publicly Owned Entity		Matt Ide	
Vermont Electric Company	Transmission	Frank Etori		
Vermont Energy Investment Corporation	AR-LR			Doug Hurley
Vermont Public Power Supply Authority	Publicly Owned Entity			Brian Forshaw
Versant Power	Transmission	Dave Norman		
Village of Hyde Park (VT) Electric Department	Publicly Owned Entity	Dave Cavanaugh		
Wakefield Municipal Gas & Light Department	Publicly Owned Entity		Matt Ide	
Wallingford DPU Electric Division	Publicly Owned Entity		Dave Cavanaugh	
Wellesley Municipal Light Plant	Publicly Owned Entity		Dave Cavanaugh	
West Boylston Municipal Lighting Plant	Publicly Owned Entity		Matt Ide	Dan Murphy
Westfield Gas & Electric Department	Publicly Owned Entity		Dave Cavanaugh	
ZTECH, LLC	End User			Bill Short

**SPECIAL APRIL 30, 2026 WEBEX PARTICIPANTS COMMITTEE MEETING
VOTE ON ATTACHMENT F REVISIONS (BASE ROE)**

TOTAL

Sector/Group	Vote
GENERATION	0.00
TRANSMISSION	16.67
SUPPLIER	0.00 ¹
ALTERNATIVE RESOURCES	0.00
PUBLICLY OWNED ENTITY	0.00
END USER	0.00
% IN FAVOR	16.67

GENERATION SECTOR

Participant Name	Vote
Dartmouth Power Associates	A
Dominion Energy Generation Mktg	A
FirstLight Power Management, LLC	A
Generation Bridge Companies	O
Granite Shore Power Companies	A
NextEra Energy Resources, LLC	A
Pawtucket Power Holding Co.	A
IN FAVOR (F)	0
OPPOSED (O)	1
TOTAL VOTES	1
ABSTENTIONS (A)	6

ALTERNATIVE RESOURCES SECTOR

Participant Name	Vote
Renewable Generation Sub-Sector	
ENGIE Energy Marketing NA, Inc.	O
H.Q. Energy Services (U.S.) Inc.	A
Load Response Sub-Sector	
Icetec Energy Services, LLC	O
Vermont Energy Investment Corp.	A
IN FAVOR (F)	0
OPPOSED (O)	2
TOTAL VOTES	2
ABSTENTIONS (A)	2

TRANSMISSION SECTOR

Participant Name	Vote
Avangrid (CMP/UI)	F
Eversource	F
National Grid	F
Rhode Island Energy	F
VELCO	A
Versant Power	F
IN FAVOR (F)	5
OPPOSED (O)	0
TOTAL VOTES	5
ABSTENTIONS (A)	1

SUPPLIER SECTOR

Participant Name	Vote
Constellation Energy Generation	A
Cross-Sound Cable Company	A
Gabel Associates, Inc.	A
Galt Power, Inc.	A
LIPA	A
Marble River, LLC	X ¹
NRG Business Marketing, LLC	O
Shell Energy North America (US) LP	A
IN FAVOR (F)	0
OPPOSED (O)	1
TOTAL VOTES	2
ABSTENTIONS (A)	6

¹ [note: A vote in favor by a Supplier Sector Participant was incorrectly registered during the meeting. The Supplier Sector Participant voting in favor was, as a result of an ongoing Financial Assurance Default at the time of the vote, suspended from voting on matters before the Participants Committee (see

Financial Assurance Policy Section III.B.2.c). The vote tabulation included as Attachment 2 to these minutes has been revised to reflect the removal of that vote, with the Supplier Sector total in favor reduced to 0% and the overall vote in favor reduced to 16.67%.]

**SPECIAL APRIL 30, 2026 WEBEX PARTICIPANTS COMMITTEE MEETING
VOTE ON ATTACHMENT F REVISIONS (BASE ROE)**

END USER SECTOR

Participant Name	Vote
Acadia Center	O
Bath Iron Works	O
Conn. Office of Consumer Counsel	O
Conservation Law Foundation	O
Elektrisola, Inc.	O
Fiscal Alliance Foundation	O
Garland Manufacturing Co.	O
Green Oceans	O
Hammond Lumber Co.	O
Harvard Dedicated Energy Limited	O
High Liner Foods	O
Industrial Energy Consumer Group	O
Industrial Wind Action Corp.	O
Lamson, John	A
Maine Public Advocate Office	O
Maine Skiing, Inc.	O
Mass. Attorney General's Office	O
Moore Company	O
NH Office of Consumer Advocate	O
Nylon Corporation	O
PowerOptions, Inc.	O
RI Division of Public Utilities Carriers	O
St. Anslem	O
Shipyard Brewing Co.	O
Z-TECH, LLC	O
IN FAVOR (F)	0
OPPOSED (O)	24
TOTAL VOTES	24
ABSTENTIONS (A)	1

PUBLICLY OWNED ENTITY SECTOR

Participant Name	Vote
Ashburnham Municipal Light Plant	O
Belmont Municipal Light Dept.	O
Block Island Utility District	O
Boylston Municipal Light Dept.	O
Braintree Electric Light Dept.	O
Chicopee Municipal Lighting Plant	O
Clear River Electric and Water District	O
Concord Municipal Light Plant	O
Conn. Municipal Electric Energy Coop.	A
Danvers Electric Division	O
Georgetown Municipal Light Dept.	O
Groton Electric Light Dept.	O
Groveland Electric Light Dept.	O

PUBLICLY OWNED ENTITY SECTOR (cont.)

Participant Name	Vote
Hingham Municipal Lighting Plant	O
Holden Municipal Light Dept.	O
Holyoke Gas & Electric Dept.	O
Hudson Light and Power Dept.	O
Hull Municipal Lighting Plant	O
Ipswich Municipal Light Dept.	O
Littleton (MA) Electric Light Dept.	O
Mansfield Municipal Electric Dept.	O
Marblehead Municipal Light Dept.	O
Mass. Municipal Wholesale Electric Co.	O
Mass. Bay Transportation Authority	O
MDC – The (CT) Metropolitan District	O
Merrimac Municipal Light Dept.	O
Midcoast Regional Redevelopment Authority	O
Middleborough Gas and Elec. Dept.	O
Middleton Municipal Electric Dept.	O
New Hampshire Electric Cooperative	O
North Attleborough Electric Dept.	O
Norwood Municipal Light Dept.	O
Paxton Municipal Light Dept.	O
Peabody Municipal Light Plant	O
Princeton Municipal Light Dept.	O
Reading Municipal Light Dept.	O
Rowley Municipal Lighting Plant	O
Russell Municipal Light Dept.	O
Shrewsbury Electric & Cable Operations	O
South Hadley Electric Light Dept.	O
Sterling Municipal Electric Light Dept.	O
Stowe (VT) Electric Dept.	A
Taunton Municipal Lighting Plant	O
Templeton Municipal Lighting Plant	O
Vermont Public Power Supply Authority	A
Village of Hyde Park (VT) Electric Dept.	A
Wakefield Municipal Gas and Light Dept.	O
Wallingford (CT), Town of	O
Wellesley Municipal Light Plant	O
West Boylston Municipal Lighting Plant	O
Westfield Gas & Electric Light Dept.	O
IN FAVOR (F)	0
OPPOSED (O)	47
TOTAL VOTES	47
ABSTENTIONS (A)	4

PRELIMINARY

Pursuant to notice duly given, a meeting of the NEPOOL Participants Committee was held beginning at 10:00 a.m. on Thursday, May 7, 2026, at the Delamar in West Hartford, Connecticut. A quorum, determined in accordance with the Second Restated NEPOOL Agreement, was present and acting throughout the meeting. Attachment 1 identifies the members, alternates, and temporary alternates who participated in the meeting.

Ms. Sarah Bresolin, Chair, presided, and Mr. Sebastian Lombardi, Secretary, recorded. Ms. Bresolin welcomed the members, alternates and guests who were present.

EXECUTIVE SESSION

VOTE ON SLATE OF CANDIDATES FOR ISO BOARD

Ms. Bresolin indicated that discussion of the proposed slate of candidates for the ISO Board would proceed in executive session. She then introduced Mr. Brook Colangelo, ISO Board Member and Chairman of the Joint Nominating Committee (JNC), who joined this portion of the meeting to present and answer any questions regarding the JNC-recommended slate and the process undertaken to identify that slate. Following general comments on the JNC process, Mr. Colangelo identified the candidates, referring to the materials that were circulated to the Committee's members and alternates in advance of the meeting. Mr. Colangelo then left the meeting.

The slate was then discussed in executive session among members and alternates, with initial comments on the candidates offered by the NEPOOL representatives who participated in the JNC efforts. While there were no concerns with the slate presented, some members identified their continuing concerns with voting on Board candidates by way of a slate, rather

than by individual candidate. Other members noted the benefits to the candidate search and overall satisfaction with the results of the slate voting approach as required under the Participants Agreement. Following further discussion, the following motion was duly made, seconded and approved by more than the 70% Vote required for approval, with the vote accomplished by confidential written ballot:

RESOLVED, that the Participants Committee endorses the slate of candidates for the ISO Board that has been recommended by the Joint Nominating Committee and presented to the Participants Committee in executive session at this meeting.

Members were advised that the election of the slate would officially be taken by the ISO Board, likely at the Board's next regularly-scheduled meeting later that month, with the results of that action to be announced publicly promptly thereafter. Until that time, members were cautioned to keep confidential the composition of the slate, particularly the identity of the candidate proposed for a first term.

GENERAL SESSION

Following a short recess, the Committee came out of executive session at 10:30 a.m. and was joined by ISO representatives, State officials and guests. Ms. Bresolin welcomed the members, alternates, State officials (including three Commissioners from Connecticut's Public Utilities Regulatory Authority -- Vice-Chairman David Arconti and Commissioners Janice Beecher and Holly Cheeseman), and guests who were present.

Before proceeding to the first general session agenda item, Ms. Bresolin briefly summarized meetings that she and Mr. Lombardi had had the week before with FERC Chairman Swett and Commissioner LaCerte, the purpose of which was to provide an introduction to NEPOOL and the New England stakeholder process. The meetings also included a preview of

several filings expected to come before the FERC in the next few months. Ms. Bresolin characterized the meetings, as well as the feedback on New England's efforts, as positive.

APPROVAL OF APRIL 9, 2026 MEETING MINUTES

Ms. Bresolin referred the Committee to the preliminary minutes of the April 9, 2026 meeting, as circulated and posted in advance of the meeting. Following motion duly made and seconded, the preliminary minutes of that meeting were unanimously approved as circulated in advance of the meeting, with additional non-material clarifications, and with an abstention by Mr. Jon Lamson noted.

CONSENT AGENDA

Ms. Bresolin then referred the Committee to the Consent Agenda that was circulated and posted in advance of the meeting. Following motion duly made and seconded, the Consent Agenda was unanimously approved, with an abstention by Mr. Lamson noted.

ISO SYSTEMS & MARKET OPERATIONS REPORT

Mr. Stephen George, ISO Vice President of System & Market Operations and Capital Projects, referred the Committee to the May System & Market Operations Report (Report), which had been circulated and posted in advance of the meeting. Noting that data in the Report was through April 29, 2026 unless otherwise noted, Mr. George reviewed Report highlights, which included: (i) the Peak Hour for April 2026, with 15,021 MW of Revenue Quality Metered (RQM) Data, occurred on April 2 during the hour ending at 8:00 p.m.; (ii) April averages for Day-Ahead Hub Locational Marginal Price (LMP) (\$45.89/MWh), Real-Time Hub LMP (\$45.50/MWh), and natural gas prices (\$2.31/MMBtu); (iii) Energy Market value for April 2026

was \$439 million, up from \$400 million in April 2025; (iv) Ancillary Markets value (\$2.5 million) was down from \$7.3 million in April 2025; (v) average Day-Ahead cleared physical energy during the peak hours as a percentage of forecasted load was 99.4% during April, down from 99.7% during March; (vi) Net Commitment Period Compensation (NCPC) payments for April totaled \$2.8 million (representing just 0.6% of April's monthly Energy Market value), comprised of (a) \$2.7 million in First Contingency payments (including \$609,000 in Dispatch Lost Opportunity Costs, \$276,000 in Rapid Response Pricing Opportunity Costs, and \$3,000 paid to Real-Time Deviations), (b) \$117,000 in Second Contingency and less than \$1,000 in voltage payments, and (c) \$30,000 in Distribution payments; and (vii) a Forward Capacity Market (FCM) value of \$88.8 million.

Mr. George highlighted a few additions to the Report that would be updated and included in future reports. The first was a chart that illustrated how, on a daily basis, temperatures departed from normal, with the gray "Mean Departure" line representing a rolling average starting on day one and recalculated each day (the April 2026 average temperature was 1°F warmer than normal). He also highlighted that, in response to member requests for additional visibility into wind and solar forecast errors, links were added to the ISO website where forecast information is updated monthly (typically by the 15th of the month) and those links would be included in monthly reports going forward.

Mr. George also noted that, on May 1, as announced at the April Reliability Committee meeting, the Ten-Minute Reserve Requirement was lowered from 120% (where it had been for the last ten years) to 115% of the largest single contingency on the system. The ISO planned to evaluate that Requirement through the fall, and review with the Reliability Committee any further modifications to that Requirement before the start of the Winter period. That evaluation

would potentially take into account a number of things, including ISO performance and response to operational contingencies, and the performance of resources that will reach commercial status (e.g. large-scale batteries and offshore wind).

In response to members' questions, Mr. George explained why Real-Time exports had been curtailed on a couple of days in April (to avoid reserve deficiencies at or around the peak hour that would have been occurred given exports exceeding those planned for in Day-Ahead clearing, combined with load running above forecast). He also confirmed that, due to planned and force outages, generation outages reached approximately 10,000 MW in April, but were accommodated through the outage coordination process, which maintained sufficient supply to meet demand, even in the face of somewhat volatile weather conditions. April NCPC payments were attributable to a combination of transmission and generation outages, in particular the need to ensure sufficient generation in the east to balance west-to-east flows. Noting that the load forecasting metric for the peak hour had been met, but the all-hours metric had not been met, in April, Mr. George assured members that the ISO's three behind-the-meter photovoltaic (PV) forecasters continued to refine their processes and protocols (with particular focus on the art and science of forecasting cloud cover) and the ISO continued to look for ways to improve its forecasts.

Turning to transmission outages, Mr. George stated that, while there were planned transmission outages throughout May, most were to be of short duration (1 day or less), and not worth specifically calling to members' attention. Mr. George noted plans to add to future monthly reports a slide identifying impactful transmission outages, which members said would be a welcome enhancement.

In response to a question about Day-Ahead Ancillary Services (DAAS) results, Mr. George replied that he would at a future meeting provide clarification as to which cost would most closely resemble the total \$/MWh that a customer would see on their bill. He also encouraged members to provide feedback on other potential refinements to the ISO's DAAS reporting.

LITIGATION REPORT

Mr. Lombardi referred the Committee to the May 6, 2026 Litigation Report that had been circulated and posted before the meeting. Mr. Lombardi highlighted a request for rehearing filed by the New England Transmission Owners of the FERC's *Opinion 594*, which reduced the base return on equity (ROE). Recalling the discussion and vote on the PTO-AC's proposed changes to the base ROE at the April 30 special Participants Committee meeting the week before, he confirmed that the proposal was filed with FERC on April 30. Mr. Lombardi stated that NEPOOL would submit a pleading providing additional information about the accelerated process that NEPOOL undertook to consider the changes and the vote taken at the April 30 meeting. In response to a question, Mr. Lombardi, after a brief explanation of the protocol followed by Counsel for filings of this nature, including Participant officer guidance and feedback, clarified that the comments in the ROE proceeding would be procedure-focused and fact-based, identifying the process undertaken to get to the votes and the position ultimately taken by the Committee at the meeting.

COMMITTEE REPORTS

Markets Committee (MC). Mr. Ben Griffiths, MC Vice-Chair, reported that the next MC meeting would be a three-day meeting, from May 12-14, 2026, at the Framingham Renaissance.

He noted that the agenda was expected to be quite full, including votes on Pay-for-Performance (PFP) revisions, including two stakeholder amendments; discussions on a multitude of Capacity Auction Reforms: Seasonal/Accreditation (CAR-SA)-related topics, including natural gas-fired resource contract requirements and demand curves, and stakeholder presentations on resource accreditation.

Reliability Committee. Mr. Frank Etori, the RC Vice-Chair, reported that the next RC meeting would be held on Thursday, May 21, 2026, also at the Framingham Renaissance. He said that discussion would include operating and planning procedure updates for Storage as a Transmission-Only Asset (SATO), *Order 881* and *Order 2023*-related issues, discussion on Power System Simulator for Engineering (PSS/E) Version 36, and several CAR-SA presentations addressing tie benefits, capacity zone formation, and distributed energy capacity resources.

Transmission Committee (TC). Mr. Dave Burnham, TC Vice-Chair, reported that the next TC meeting would be held on May 28, 2026, and if held in person, at the Milford Doubletree. He reported that the agenda was still being developed, but he expected further discussion of the asset condition project (ACP) reviewer subject, including potential Participant amendments to the ISO's ACP reviewer framework.

Budget & Finance Subcommittee (B&F). Mr. Tom Kaslow, B&F Chair, reported that the B&F would convene on May 8, 2026. He noted that the agenda would include several "regular" budget reports, as well as amendments to the Financial Assurance Policy (FAP) associated with external transactions and PFP-related balancing ratio changes.

Membership Subcommittee. Mr. Brian Thomson, the Membership Subcommittee Chair, reported that the next Membership Subcommittee meeting would be held virtually on May 11,

2026. He expected the Subcommittee to take action on one application and one termination request.

ADMINISTRATIVE MATTERS

Mr. Lombardi introduced Ms. Laura Clark, who recently joined the NEPOOL team and would be assisting with all Committee administrative matters. He reminded members who had not done so already to register for the June 16-18, 2026 Summer Meeting in Newport, Rhode Island, which was expected to be well attended. Ms. Bresolin added that the Summer Meeting was likely to be quite busy, with votes on both DAAS and PFP changes, and detailed reports from both the external and internal market monitors, in addition to a full slate of modified Sector meetings with the ISO Board, and representatives from the New England States and the FERC.

Ms. Bresolin announced that Ms. Maria Gulluni, ISO New England's General Counsel, would be receiving later that evening the Leadership Award from the New England Women in Energy and the Environment (NEWIEE), recognizing Ms. Gulluni for her 25-year career in the industry, her leadership, and her dedication to advancing equity and mentoring young professionals. On behalf of NEPOOL and its members, she congratulated Ms. Gulluni for the well-deserved recognition.

There being no other business, the meeting adjourned at 11:07 am.

Respectfully submitted,

Sebastian Lombardi, Secretary

**PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN THE MAY 7, 2026 MEETING**

PARTICIPANT NAME	SECTOR/GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Acadia Center	End User	Joe LaRusso (W)		
Advanced Energy United	Assoc. Non-Voting		Alex Lawton (W)	
Bath Iron Works Corporation	End User			Bill Short
Belmont Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Block Island Utility District	Publicly Owned Entity	Dave Cavanaugh		
BP Energy Company	Supplier			Jose Rotger
Braintree Electric Light Department	Publicly Owned Entity		Dave Cavanaugh	
Brookfield Renewable Trading and Marketing LP	Supplier	Aleks Mitreski (W)		
Central Maine Power/UI	Transmission	Alan Trotta	Jason Rauch (W)	
Chester Municipal Light Department	Publicly Owned Entity			Brian Forshaw (W)
Clear River Electric	Publicly Owned Entity		Dave Cavanaugh	
CLEAResult Consulting, Inc.	AR-DG	Tamera Oldfield (W)		
Concord Municipal Light Plant	Publicly Owned Entity		Dave Cavanaugh	
Conn. Municipal Electric Energy Cooperative	Publicly Owned Entity	Brian Forshaw (W)		
Conn. Office of Consumer Counsel	End User	Claire Coleman	Jamie Talbert-Slagle	
Conservation Law Foundation	End User	Nick Krakoff (W)		
Constellation Energy Generation, LLC	Supplier	Andy Gillespie (W)		
Cross-Sound Cable	Supplier		Jose Rotger	
Danvers Electric Division	Publicly Owned Entity		Dave Cavanaugh	
Dartmouth Power Associates, L.P.	Generation		Sarah Yasutake (W)	
Dominion Energy Generation Marketing, Inc.	Generation	Wes Walker (W)		
DTE Energy Trading, Inc.	Supplier			Jose Rotger
Earthjustice	End User		Ada Statler (W)	
Elektrisola, Inc.	End User			Bill Short
ENGIE Energy Marketing NA, Inc.	AR-RG	Sarah Bresolin		
Eversource Energy	Transmission		Dave Burnham	
FirstLight Power Management, LLC	Generation	Tom Kaslow		
Fiscal Alliance Foundation, Inc.	End User			Lisa Linowes (W)
Gabel Associates, Inc.	Supplier	Sarah Yasutake (W)		
Galt Power, Inc.	Supplier	Jose Rotger		
Garland Manufacturing Company	End User			Bill Short
Georgetown Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Granite Shore Companies	Generation			Bob Stein
Green Oceans	End User		Lauren Knight (W)	
Groveland Electric Light Department	Publicly Owned Entity		Dave Cavanaugh	
H.Q. Energy Services (U.S.) Inc.	AR-RG	Louis Guilbault (W)	Robert Stein	
Hammond Lumber Company	End User			Bill Short
Harvard Dedicated Energy Limited	End User			Doug Hurley (W)
High Liner Foods (USA) Incorporated	End User		Bill Short	
Hingham Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Holden Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Hudson Light and Power Department	Publicly Owned Entity			Dave Cavanaugh
Industrial Wind Action Corp	End User	Lisa Linowes (W)		
Lamson, Jon	End User	Jon Lamson (W)		
Littleton (MA) Electric Light and Water Dept.	Publicly Owned Entity		Dave Cavanaugh	
Maine Public Advocate Office	End User			Susan Chamberlin (W)
Mass. Attorney General's Office	End User	Jacquelyn Bihle	Jamie Donovan	Chris Modlish
Mass. Bay Transportation Authority	Publicly Owned Entity		Dave Cavanaugh	
Mass. Municipal Wholesale Electric Co.	Publicly Owned Entity			Brian Forshaw (W)
MDC – The (CT) Metropolitan District	Publicly Owned Entity		Dave Cavanaugh	
Mercuria Energy America, LLC	Supplier			Jose Rotger
Merrimac Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Midcoast Regional Redevelopment Authority	Publicly Owned Entity		Dave Cavanaugh	
Middleborough Gas & Electric Department	Publicly Owned Entity		Dave Cavanaugh	

(W) = Webex

**PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN THE MAY 7, 2026 MEETING**

PARTICIPANT NAME	SECTOR/GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Middleton Municipal Electric Department	Publicly Owned Entity		Dave Cavanaugh	
National Grid	Transmission	Tim Brennan (W)	Tim Martin	
New England Power Generators Association	Assoc. Non-Voting	Bruce Anderson	Dan Dolan	
New Hampshire Electric Cooperative, Inc.	Publicly Owned Entity			Brian Forshaw (W)
NextEra Energy Resources, LLC	Generation	Michelle Gardner (W)		
NH Office of Consumer Advocate	End User	Matthew Fossum		
North Attleborough Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Norwood Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
NRG Business Marketing, LLC	Supplier	Ben Griffiths (W)		
Nylon Corporation of America	End User			Bill Short
Pawtucket Power Holding Company LLC	Generation	Dan Allegretti		
PowerOptions, Inc.	End User			Doug Hurley (W)
Reading Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Rhode Island Energy	Transmission	Brian Thomson	Robin Lafayette	
RI Division (DPUC)	End User		Christy Hetherington	
Rowley Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Saint Anselm College	End User			Bill Short
Shell Energy North America (US), L.P.	Supplier	Jeff Dannels		
Shipyards Brewing LLC	End User			Bill Short
Stowe Electric Department	Publicly Owned Entity		Dave Cavanaugh	
SYSO Inc.	AR-DG			Alex Worsley
Taunton Municipal Lighting Plant	Publicly Owned Entity	Nick Parrotta (W)	Dave Cavanaugh	
The Moore Company	End User			Bill Short
Union of Concerned Scientists	End User	Susan Muller (W)		
VELCO	Transmission	Frank Etori		
Veolia Flexible Energy Services North America	AR-LR	Doug Hurley (W)		
Vermont Energy Investment Corporation	AR-LR			Doug Hurley (W)
Vermont Public Power Supply Authority	Publicly Owned Entity			Brian Forshaw (W)
Versant Power	Transmission	Dave Norman	Stephen Johnston	
Village of Hyde Park (VT) Electric Department	Publicly Owned Entity	Dave Cavanaugh		
Vistra (Dynegy Marketing and Trade, LLC)	Generation	Ryan McCarthy		
Wallingford DPU Electric Division	Publicly Owned Entity		Dave Cavanaugh	
Wellesley Municipal Light Plant	Publicly Owned Entity		Dave Cavanaugh	
Westfield Gas & Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Z-TECH, LLC	End User			Bill Short

(W) = Webex

CONSENT AGENDA

REMOVED FROM CONSENT AGENDA; TO BE DISCUSSION ITEM #10A

Markets Committee (MC)

From the previously-circulated notice of actions of the MC's May 12-14, 2026 meeting, dated May 15, 2026.¹

1. Changes to the GIS and GIS Operating Rules (MA Section 83D Changes)²

Approve proposed changes to the NEPOOL Generation Information System (GIS) and GIS Operating Rules related to marking of Certificates as being transferred under Section 83D of the Massachusetts Act Relative to Green Communities, as recommended by the MC at its May 12-14, 2026 meeting, together with such further non-material changes as may be approved by the Chair of the GIS Operating Rules Working Group.

The motion to recommend Participants Committee support was approved unanimously, with 2 abstentions noted (1 Supplier, 1 End User).

Reliability Committee (RC)

From the previously-circulated notice of actions of the RC's May 21, 2026 meeting, dated May 21, 2026.³

2. Revisions to OP Nos. 3, 4, 7, 12, 14 (including a new Appendix J), 18, and 19 (SATO Conforming Changes)

Support proposed revisions to the following ISO-NE Operating Procedures (OP): No. 3 (Transmission Outage Scheduling), No. 4 (Action During a Capacity Deficiency), No. 7 (Action In An Emergency), No. 12 (Voltage and Reactive Control), No. 14 (Technical Requirements For Assets and Resources), including a new OP No. 14 Appendix J (Storage As Transmission-Only Asset Operator Guide), No. 18 (Metering and Telemetering Criteria), and No. 19 (Transmission Operations), as recommended by the RC at its May 21, 2026 meeting, together with such non-material changes as may be approved by the RC Chair and Vice-Chair.

The motion to recommend Participants Committee support was approved unanimously.

¹ MC Notices of Actions are posted on the ISO-NE website at: <https://www.iso-ne.com/committees/markets/markets-committee/?document-type=Committee%20Actions>.

² APX, Inc., the Generation Information System (GIS) Administrator, estimates that implementing this change to the GIS will take 281 development hours. Under Rule 1.3 of the NEPOOL GIS Rules, changes to the GIS that require 50 hours or more of labor or have an estimated cost to NEPOOL of more than \$30,000 and that in either case are not required to address a change in law or a change in the ISO Tariff must be approved by the NEPOOL Participants Committee.

³ RC Notices of Actions are posted on the ISO-NE website at: <https://www.iso-ne.com/committees/reliability/reliability-committee/?document-type=Committee Actions>.

3. Revisions to OP-16, including its Appendices A, B, C, D, E, G, H, & I (Orders 881/881-A Conforming Changes)

Support proposed revisions to OP No. 16 (Transmission System Data), including its Appendices A (Explanation of Terms and Instructions for Data Preparation of NX9-A), B (Explanation of Terms and Instructions for Data Preparation of NX9-B), C (Explanation of Terms and Instructions for Data Preparation of NX9-C), D (Explanation of Terms and Instructions for Data Preparation of NX-9D), E (Annual Certification), G (Explanation of Terms and Instructions for Data Preparation of NX-9), H (Explanation of Terms and Instructions for Data Preparation of NX-9H), and I (Explanation of Terms and Instructions for Data Preparation of NX-9 (Other Equipment)), as recommended by the RC at its May 21, 2026 meeting, together with such non-material changes as may be approved by the RC Chair and Vice-Chair.

The motion to recommend Participants Committee support was approved unanimously.

4. Retirement of OP-17 Appendix B

Support proposed retirement of Appendix B (Methodology For Developing Load Power Factor Standards) to OP-17 (Load Power Factor and System Assessment), as recommended by the RC at its May 21, 2026 meeting, together with such non-material changes as may be approved by the RC Chair and Vice-Chair.

The motion to recommend Participants Committee support was approved unanimously with one abstention in the Transmission Sector.

5. Revisions to Planning Procedures Nos. 5-3 & 7 (Order 881 Conforming Changes)

Support proposed revisions to ISO-NE Planning Procedure (PP) No. 5-3 (Guidelines for Conducting and Evaluation Proposed Plan Application Analyses) and PP-7 (Procedures for Determining and Implementing Transmission Facility Ratings in New England), as recommended by the RC at its May 21, 2026 meeting, together with such non-material changes as may be approved by the RC Chair and Vice-Chair.

The motion to recommend Participants Committee support was approved unanimously.

6. Revisions to PP-10 (Order 2023 Conforming Changes)

Support proposed revisions to PP-10 (Planning Procedure to Support the Forward Capacity Market), as recommended by the RC at its May 21, 2026 meeting, together with such non-material changes as may be approved by the RC Chair and Vice-Chair.

The motion to recommend Participants Committee support was approved unanimously.

**Summary of ISO New England Board and Committee Meetings
June 16, 2026 Participants Committee Meeting**

Since the last update, the Audit and Finance Committee and the Nominating and Governance Committee met on May 20, and the Markets Committee met on May 21. The Board of Directors met on May 20 and 21. All of the meetings were held in Holyoke, Massachusetts.

The Audit and Finance Committee reviewed the Company's financial performance against the 2026 budget, and approved the first quarter's unaudited financial statements after management confirmed that all relevant disclosures were included in the financial statements. Next, the Committee discussed the preliminary 2027 operating and capital budgets. The Committee discussed the factors contributing to the increased budgets, including the complexity of various projects, inflationary increases, and the need to invest in artificial intelligence. The Committee also considered the impact on ratepayers of the increase. The Committee reviewed a draft of the Company's 2025 tax return on Form 990. The Committee considered management's proposal to update the Company's purchase order approval levels for management, and agreed to recommend that the Board approve the changes. Finally, the Committee was provided with an update on the potential purchase of land to support a new building, including conference space, in Holyoke.

The Nominating and Governance Committee received an update on the conclusion of the Joint Nominating Committee process for 2025 and formally nominated the slate of directors for election in 2026 (Kathryn Guarini, Craig Ivey, and Mark Vannoy). The Committee held a preliminary discussion regarding assignments to Board committees and succession planning for board leadership positions, all in advance of the next Board year that begins on October 1, 2026. The Committee also discussed the orientation program for director-elect, Kathryn Guarini. Next, the Committee discussed issues that are "top of mind" for the Board, in advance of meetings with the NEPOOL sectors in June. In executive session, the Committee reviewed the Board and committees' self-evaluation responses.

The Markets Committee was provided with a review from both the Internal and External Market Monitors of market performance in winter 2025-2026. Next, the Committee provided final comments on the Internal Market Monitor's draft annual markets report, which assesses the competitiveness of the wholesale markets and reviews market pricing outcomes. The Committee then received updates on Day-Ahead Ancillary Services and the Capacity Auction Reforms projects.

The Board of Directors (acting as the members of the corporation) held its annual meeting of members and elected Ms. Guarini and Messrs. Ivey and Vannoy to the Board of Directors for three-year terms, effective October 1, noting that the slate was previously approved by the NEPOOL Participants Committee at its May 7th meeting. The Board then held a strategic planning session, looking ahead five years. The next day, the Board resumed its meeting and received a report from management on current business, and discussed activities related to the Federal Energy Regulatory Commission, federal executive and legislative branches, and the New England states. The Board also received a report from the Chief Financial Officer, and prepared for the upcoming ISO/RTO Council Conference. The Board received reports from the standing committees, and during the Nominating and Governance Committee report, reviewed topics for discussion with the NEPOOL Sectors in June, and an onboarding program for the new director. The Board concluded its meeting with an executive session.

ISO New England 2027 and 2028 Preliminary Operating and Capital Budgets



*NEPOOL Participants Committee 2026
Summer Meeting*

Kelly Reyngold

VP, CHIEF FINANCIAL OFFICER



Contents of Presentation

- Executive Summary..... 3
- Strategic Planning Process Overview..... 9
- 2027 and 2028 Preliminary Budget Overview..... 15
- Appendix 1: 2027 Detailed Budget Changes by Strategic Goal..... 27
- Appendix 2: 5 Year Budget Comparison..... 38
- Appendix 3: Forward Looking Capital Budget Spending..... 40
- Appendix 4: 2027 Preliminary Capital Budget..... 47
- Appendix 5: Capital Structure..... 51
- Appendix 6: Historical New England Energy Costs..... 53
- Appendix 7: Examples of Innovation and Use of Artificial Intelligence..... 57



EXECUTIVE SUMMARY

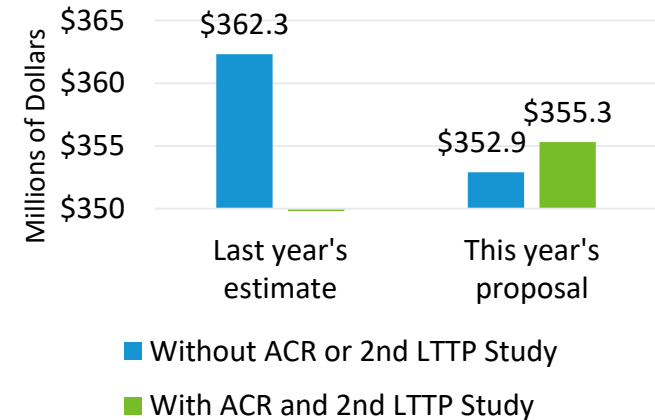
Executive Summary

- The 2027 ISO-NE budget continues to support the region's needs and evolving grid while reinforcing our commitment to affordability, reliability, and long-term value
- Investments are aligned to deliver high-quality services to the region amid increasing uncertainty in regional supply and demand
 - Continued focus on innovation and agility to respond to such uncertainty
 - Appendix 7 highlights examples of how the ISO is currently leveraging innovation and AI to enhance responsiveness and drive operational performance
- Continued emphasis on operational efficiency and disciplined cost management
- Affordability remains a core lens: balancing necessary investment with cost impacts to stakeholders

Executive Summary

- The projected 2027 ISO-NE budget, based on assumptions previewed with stakeholders during the 2026 budget cycle, was \$362.3M
 - This budget did not include costs for the permanent Asset Condition (AC) Reviewer role or a second Longer-Term Transmission Planning (LTP) Study
- The current proposed 2027 ISO-NE budget is \$355.3M and includes costs for AC Reviewer and LTP
 - Excluding costs for AC Reviewer and LTP, the proposed 2027 budget is \$352.9M, which constitutes a decrease of \$9.4M or 2.6% from the previously projected budget

Proposed Budget: 2027



Executive Summary

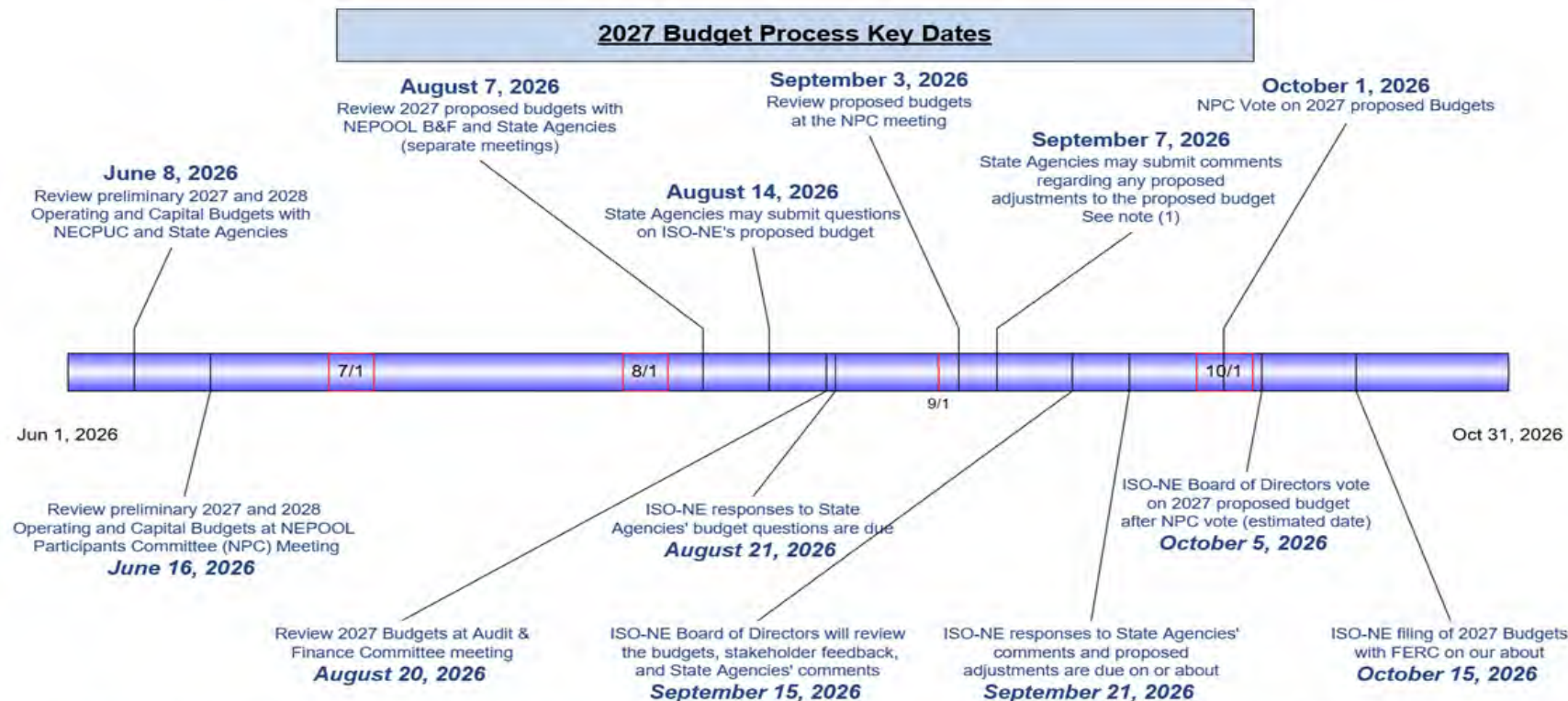
- 2027 budget increases, over the 2026 approved budget, are driven by multiple factors:
 - Key external drivers:
 - Changing resource mix and customer demand patterns
 - Ongoing system transformation independent of macro uncertainty
 - Inflationary and price escalation trends
 - Internal drivers:
 - Supporting new systems, markets, and infrastructure
 - Maintaining workforce capabilities
 - Affordability consideration: investments prioritized to maintain reliability and avoid higher long-term system costs



Executive Summary

- As ISO-NE seeks to offer increasing value to the region, we have allocated, as separate line items, \$2.4M to initiatives requested by the states and other stakeholders:
 - Asset Condition (AC) Reviewer (\$2.2M)
 - Other AC Reviewer related costs, not included in the amount above, for existing ISO staff (e.g. legal, management, and support) will be borne by the company to stand up the AC Reviewer function in 2027
 - Longer-Term Transmission Planning – second study (\$0.2M)
- Monies not spent on these two initiatives will be returned through the true-up process

2027 Budget Process – Key Dates



(1) According to the budget settlement agreement, State Agencies must submit comments on the proposed budgets five weeks after the August meeting which is September 11, 2026. However, we are requesting comments by September 7, 2026 to allow for timely distribution to the Board when meeting materials are mailed. This is consistent with the acceleration agreed to in 2015.

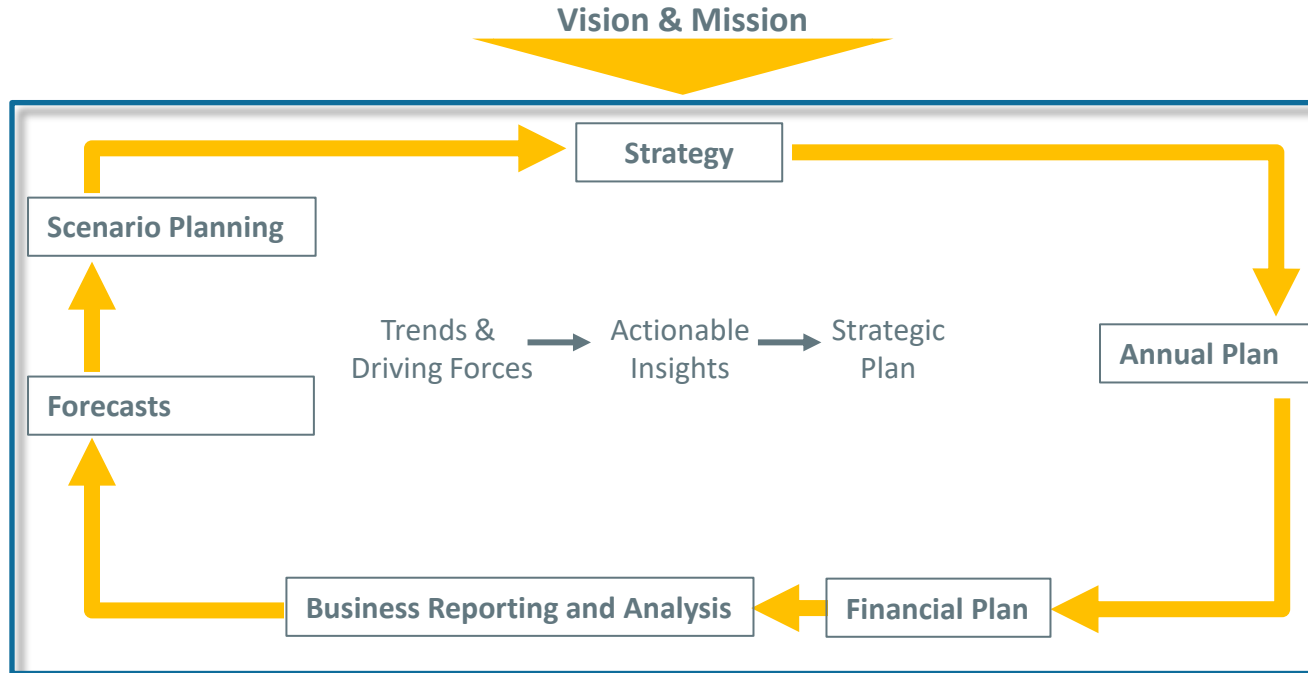
STRATEGIC PLANNING PROCESS OVERVIEW

ISO-NE's integrated business and strategic planning framework



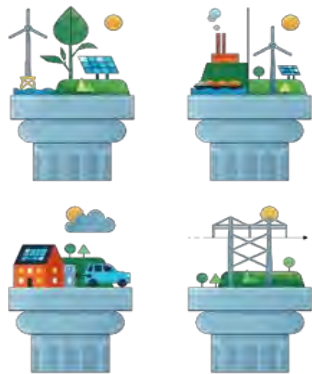
Annual Process – Business and Strategic Planning

ISO-NE is guided by a purposeful and integrated business planning approach that drives focus towards a common target that management teams and the entire organization can get behind, with the aim of creating value for ISO stakeholders



Our Guidepost: The ISO New England Vision Statement

The ISO-NE Vision Statement is an explicit statement about our intent to support the states' policy goals to achieve a reliable transition to clean energy, utilizing competitive markets and transmission planning



Vision Statement:

To harness the power of competition and advanced technologies to reliably plan and operate the grid as the region transitions to clean energy

The ISO's Vision represents the company's commitment to work with FERC, the states, and market participants to support the region's grid transition within the limits of our jurisdiction

Our Responsibility to the Region: ISO's Mission

The ISO-NE Mission Statement outlines the core role and responsibilities of the ISO's daily operations



Mission Statement:

Through collaboration and innovation, ISO New England plans the transmission system, administers the region's wholesale markets, and operates the power system to ensure reliable and competitively priced wholesale electricity

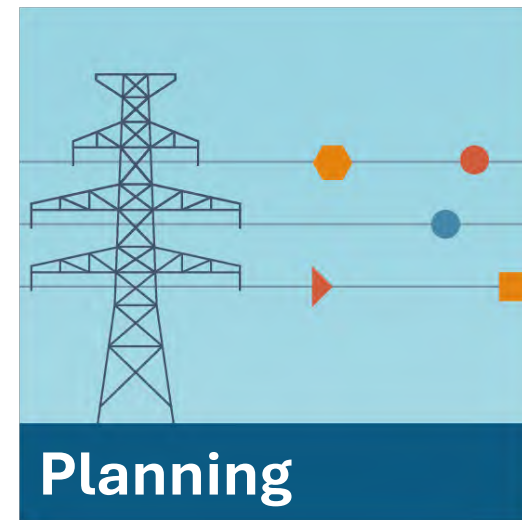
ISO New England Performs **Three Critical Roles** to Ensure Reliable Electricity at Competitive Prices



Coordinate and direct the flow of electricity over the region's high-voltage transmission system



Design, run, and administer the billion-dollar markets where wholesale electricity is bought and sold



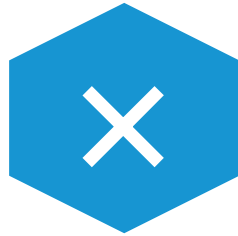
Study, analyze, and plan to make sure New England's electricity needs will be met over the next 10 years

Functions Outside of ISO Jurisdiction

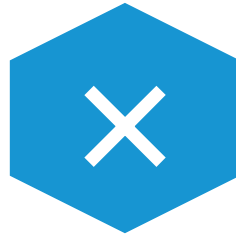
The ISO does not...



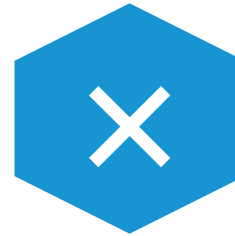
Handle
retail electricity



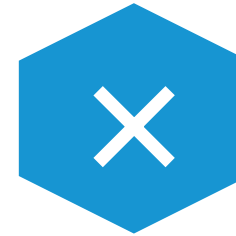
Own power grid
infrastructure



Have a stake in
companies
that own grid
infrastructure



Have
jurisdiction
over fuel
infrastructure



Have control
over siting
decisions



Plan the
resource mix

2027 AND 2028 PRELIMINARY BUDGET OVERVIEW

Our 2027 Strategy Continues to Support the Region's Grid Transition and Drives our Work and Resource Requirements

- Resources to: sustain ongoing operations; advance new market, planning, and regulatory initiatives; invest in technology and innovation
 - Continue capacity market reforms to better align with the region's evolving energy system
 - Continue to design and develop various products and support new in-service projects to administer our mission
 - Invest in AI and analytics to improve forecasting, modeling, and simulation capabilities
 - Continue strengthening cybersecurity defense mechanisms and ISO computer networks and infrastructure to protect against sophisticated threat vectors
- Resources for additional work requested by states and other stakeholders
 - Adoption of the Asset Condition (AC) Reviewer role
 - Advance additional LTTP study to support states' energy policy and address evolving system needs

2027 Preliminary Budget Overview

- In preparing the 2027 Preliminary Budget, ISO-NE sought to balance supporting the region's evolving needs, implementing new market, planning, and regulatory initiatives, increasing productivity via technology and analytics, with affordability and cost-discipline
 - The preliminary baseline budget is **\$22.9M or 6.9%** above the 2026 approved budget
 - This reflects an \$9.4M (2.6%) decrease compared to the 2027 budget levels projected based on assumptions previewed with stakeholders during the 2026 budget cycle
 - Incorporating additional AC Reviewer and LTTP services requested by states and other stakeholders increases the preliminary 2027 budget by **\$2.4M** resulting in a total increase of **\$25.3M (7.7%)** over the 2026 approved budget
 - Including both the requested AC Reviewer and LTTP services and prior year true-ups, the 2027 Revenue Requirement reflects a \$33.3M increase

Note: Throughout the presentation some schedules may appear inconsistent due to rounding.

2027 Preliminary Budget Overview *(cont.)*

- Key drivers supporting the proposed increase represent ongoing support of the stakeholder-supported workplan:
 - Changes in the resource mix and customer use patterns in New England: these changes will continue independent of federal policy, inflation, or local siting and permitting hurdles for new supply resources
 - The implementation and support of various market, transmission, and emerging technology initiatives requires increased headcount to build, maintain, and administer
 - In particular, the CAR project will require incremental resources given the volume of change and new functionality, including seasonal auctions and accreditation
 - Execution of these initiatives depends on maintaining a highly skilled workforce, requiring sustained investment in competitive compensation and benefits
- Included in the 2027 Preliminary Budget are 27 additional FTEs to support existing functions, with 7 more for the AC Reviewer role*

*To account for the staggered onboarding of newly budgeted positions, the 2027 Preliminary Budget provides funding for 33.5 additional FTEs, consisting of both proposed 2027 positions and carryover from partially funded 2026 positions.

Resources for Ongoing Operations, Technology and Innovation, Market and Transmission Initiatives and Stakeholder Requests in 2027

There are four main factors for the change to the 2027 ISO budget (separate from the revenue requirement true-up change):

1. Inflationary and Strategic Staffing to Sustain Operations
 - Workforce compensation and benefits; inflationary pressures that are enterprise-wide, with the greatest concentration in Information Technology; investments in cybersecurity defenses; and additional staffing to support Information Technology, Finance, Human Resources, and regulatory fee increases for Northeast Power Coordinating Council and North American Electric Reliability Corporation
2. Technology and Innovation Resources
 - Artificial Intelligence utilization to drive improved productivity and operations; maintenance and support for new and improved tools for System Planning and System/Market Operations
3. Market and Transmission Initiatives
 - Staff additions for CAR; Economic and Planning Studies; full Net CONE recalculation; new generation interconnection tools; and transmission planning responsibilities
4. New Services/Stakeholder Requests
 - Asset Condition Reviewer; Economic and Planning Studies and additional Longer-Term Transmission Planning efforts

Note: See the following slide for the cost impact of each these factors plus the revenue requirement true-up change

Resources for Ongoing Operations, Technology and Innovation, Market and Transmission Initiatives and Stakeholder Requests in 2027 *(cont.)*

Factor	% Increase	\$ Amount	\$KWh Rate	Average Monthly Consumer Cost Impact *
Inflationary and Strategic Staffing to Sustain Operations	3.4%	\$ 10,470,300	\$0.00009	\$0.06
Technology and Innovation Resources	2.2%	\$ 6,810,700	\$0.00006	\$0.04
Market and Transmission Initiatives	1.6%	\$ 5,064,100	\$0.00004	\$0.03
New Services/Stakeholder Requests	0.9%	\$ 2,929,600	\$0.00002	\$0.02
Net Change in Rev Req True-Up	2.5%	\$ 7,984,200	\$0.00006	\$0.05
Total Change in Revenue Req for 2027:	10.6 %	\$33,258,900	\$0.00027	\$0.20

*Average Monthly Consumer Cost Impact is based on average consumption of 750 kWh per month.

2027 Budget Drivers

- Market Initiatives
 - Capacity Auction Reforms
 - Flexible Response Services and Reserve Products
 - Next-Generation Energy Markets (nGEM) platform
- New/Additional Regulatory Initiatives
 - Longer-Term Transmission Planning
 - Asset Condition Reviewer Role
 - Managing Transmission Line Ratings
 - Grid Enhancing Technologies in Transmission Planning
 - Distributed Energy Resources participation in wholesale energy markets
 - Interconnection improvements
- Forecasting/Modeling Improvements
 - Probabilistic Forecasting Enhancements
 - Inverter-Based Resource (IBR) Integration & Modeling
 - Synchophasor Enhancements for the Future Grid
 - Resource Adequacy and Energy Security Analysis Tools



2027 Budget Drivers *(cont.)*

- Digital transformation and technology modernization efforts to improve security, reliability, and efficiency⁽¹⁾
 - The ISO's transition to a cloud environment continues to be a major effort over the next several years to reduce reliance on in-house data centers, make system deployment more efficient, and enable faster computing performance as data volume grows
 - Utilization of Artificial Intelligence (AI) and Machine Learning (ML) for items such as technology updates, cloud infrastructure provisioning, and developing of comprehensive knowledge databases
 - The ISO has included additional resources for 2027 to begin to scale AI usage
- Remaining competitive in compensation and benefits in what is still a tight labor market for the skillsets needed at the ISO
- Computer Services⁽¹⁾ including support costs for new or enhanced systems that have/will become operational in 2026 and 2027
 - nGEM Real-Time Market Clearing Engine
 - CIP Synchrophasor Improvements
 - Cyber Security Log Management, AI-enabled Cyber Security tools, and Cloud Security
 - Impact of moving applications to the cloud (noted above under Cloud Modernization) and SaaS solutions

⁽¹⁾ See the following slide for additional details on Cloud Modernization, Computer Service and Information Technology related costs

2027 Budget Drivers *(cont.)*

Like many of our peers, ISO-NE has experienced significant growth in Computer Service and Information Technology needs and related costs over the past several years and expects that to continue in 2027. This is driven by:

- AI and ML for software development and innovation
 - Utilization of AI and ML for items noted on the previous slide
 - Other examples include uses such as On-Line Weather Look-Ahead Study to estimate transmission outages under severe weather and pump storage forecast in 21-day Energy Assessment
- Ongoing support for market and operations technologies
 - Including: a software portfolio designed for grid orchestration, integrating energy data, AI-driven analytics, and grid modeling to help utilities manage modern energy complexities; and PEAT license renewal
- Increase in Data Management Costs
 - Organizations are leveraging Infrastructure-as-a-Service (IaaS) to reduce implementation time, enhance operational efficiency, and support innovation
- Software Licensing and Subscription Fees
 - Increases driven by rising software license costs, expanding user bases, and investments in enhanced tools
- Inflation, Supply-Chain Disruptions, and Tariffs
 - Ongoing geopolitical instability and supply chain challenges are contributing to price increases in electronics, machinery, and other IT-related goods

2027 Preliminary Capital Budget Overview

The 2027 Capital Budget is also presented in summary form

- The 2027 Capital Budget is \$45.0M which represents a \$2.5M or 5.9% increase over the 2026 capital budget
 - Capital budget increases over the past several years have been driven by three primary drivers as explained in further detail in Appendix 3
 - Significant projects expected for 2027 include Capacity Auction Reforms implementation, Single Interval Market Clearing Engine Implementation (transitioning Real-Time study modes to nGEM platform), and EMP 3.5 Upgrade – GridOS (to migrate ISO-NE's Energy Management System customizations to GE's Energy Management Platform version 3.5)
- The 2027 proposed capital budget of \$45.0M is provided with a list of projects by strategic goal that are currently chartered and on-going or in planning/conceptual design (see Appendix 4)
- Detailed project descriptions will be presented in August once the final resource requirements are determined

2028 Preliminary Budget Overview

2028 Budget amounts are projected as follows (over 2027 Preliminary Budget amounts presented today):

- Net Expense Before Depreciation and Regulatory Fees is \$24.2M or an 7.9% increase, while amounts including Depreciation and Regulatory Fees is a \$31.1M or 8.8% increase

2028 Budget Assumptions include:

- The addition of 25 FTEs, primarily for System Planning (for continued build out of Asset Condition Reviewer team, Resource Adequacy, Transmission Planning, and Generation Interconnections); Information Technology resources to continue servicing new market features and advanced technologies; and for support areas including participant support and training, Human Resources, and Finance
- Merit and promotional/equity annual increases consistent with 2027 amounts (4.5% total)
- Estimated increases based on market or historical trends related to: employee benefits (primarily for health insurance); Computer Services; and Insurance Expense
- Inflationary increases in other lines based on consumer price index indicator for 2028

2027 and 2028 Operating Budget Risks

- Additional resources may be needed as the 2027 work plan scope increases based on regulatory and stakeholder initiatives/requests
- Cyber risk is increasingly treated as a balance-sheet issue, with exposure to ransomware-driven downtime, third-party/vendor breaches, regulatory penalties, and critical infrastructure disruptions; risk is expected to intensify through 2027–2028 as AI-assisted attacks increase in frequency and sophistication, driving incremental investment in resilience capabilities, backup systems, identity management, cyber insurance, and incident response retainers
- Technology spend is increasingly unpredictable as AI workloads scale differently than traditional systems, creating exposure to cloud cost. Early-stage AI initiatives are rapidly converting into recurring operating expenses, driving sustained growth in AI usage, data storage, and governance requirements; as a result, software licensing and maintenance, cloud migration, and AI utilization and control frameworks are expected to require incremental and less predictable funding in future budgets
- Insurance policy renewals may be higher than estimated as ISO is not immune to overall increases from the insurance industry due to natural disasters
- Interest Rates may impact the ISO floating rates on tax-exempt debt, pension and post-retirement benefit plans liability costs, and interest income on settlement float balance
- Legal costs from material litigation that may arise during the course of the year would pose a risk to the ISO's ability to operate within the approved budget
- Federal and state policy directives/changing policies could result in additional cost associated with new requirements
- Workforce sourcing and related pay rates, supply chain disruption, and inflationary pressures may each have budgetary impacts

APPENDIX 1: 2027 Detailed Budget Changes by Strategic Goal

2027 ISO-NE Strategic Goals

The ISO ties its annual budget to resource requirements by Goals, Objectives, and Initiatives

Responsive Market Designs:

Advance the competitive wholesale markets to support the investment and new services required for a reliable clean energy transition

Progress and Innovation:

Expand capabilities to support increasing grid complexity brought about by new technologies and changes to supply mix and customer use

Operational Excellence:

Focus on high quality business operations, prioritize high impact projects, and mitigate implementation risks

Stakeholder Engagement:

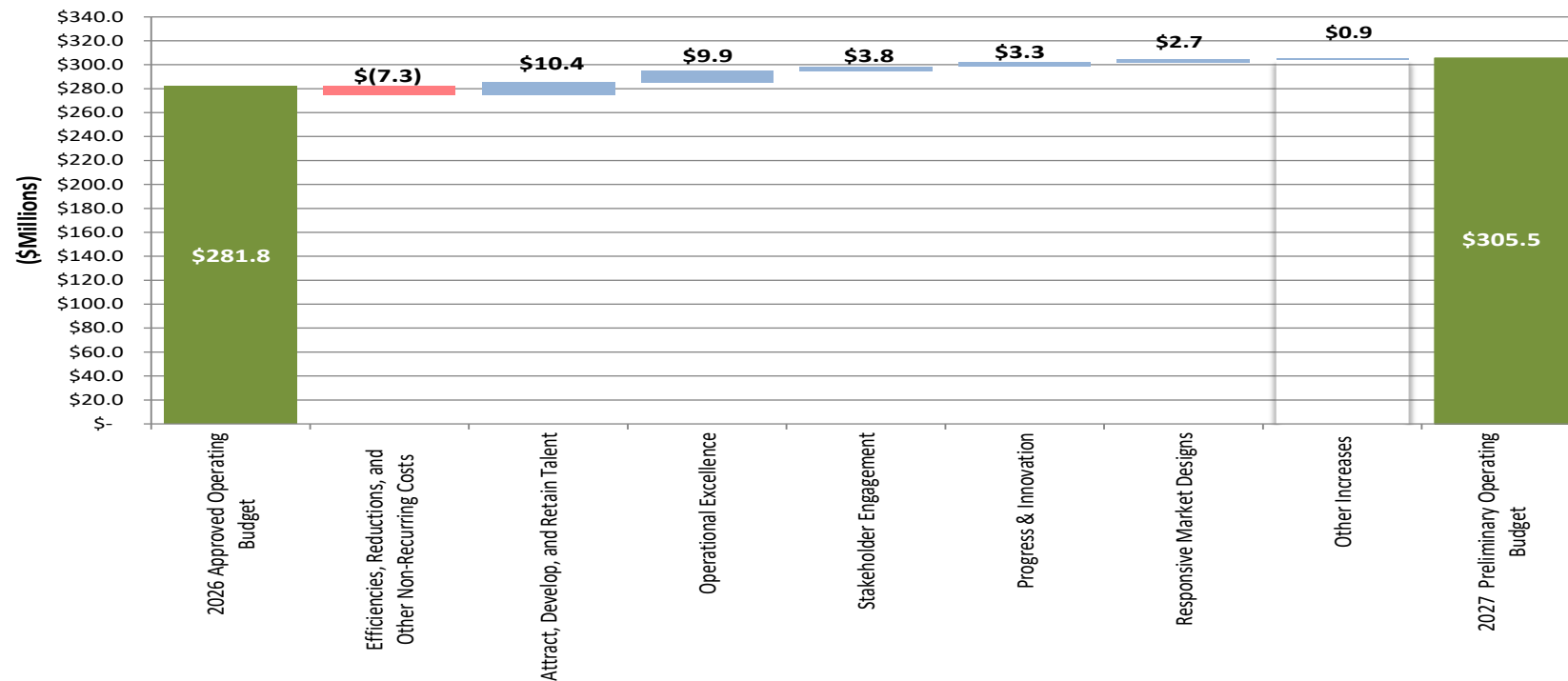
Collaboratively understand and anticipate needs, demonstrate thought leadership through high-quality analysis and communication, and nurture productive relationships with regulators and stakeholders in supporting the four pillars of the clean energy transition

Attract, Develop, and Retain Talent:

Continue to promote our Culture, Mission, Vision, and Goals; develop and position the workforce to support the evolving needs of the organization; recognize and reward employees' success and innovation; tailor programs to retain and attract critical, in-demand skills; and foster an inclusive culture that values diversity of career and life experiences

2027 Preliminary Budget

Changes in budget by Strategic Goal



2027 Preliminary Budget Details

Efficiencies, Reductions, and Other Non-Recurring Costs⁽¹⁾

Reductions include: (\$7.3M)

- Computer Services reductions driven by retired products and savings achieved through contract renewals (\$3.3M)
- Lower costs for Capacity Auction Reforms design consultant and project management as work moves from the design to development (\$1.6M)
- Lower required contributions reflect favorable investment performance and the impact of a recent pension lift-out, supporting ongoing plan de-risking (\$1.0M)
- Lower salary costs from retirements and backfilling positions with less experienced staff (\$0.5M)
- Elimination of the Holyoke facility land lease in anticipation of a planned purchase prior to 2027 (\$0.3M)
- Reduced reliance on workforce security consulting through the repurposing of an existing FTE (\$0.3M)
- Net favorable impact from changes in interest income and expense, driven by higher settlement balances and lower tax-exempt debt (\$0.3M)

(1) The items identified reflect known, quantifiable reductions. The ISO's budget also incorporates incremental savings from contract negotiations and other cost-avoidance initiatives that are not readily quantifiable. As an example, through the Oracle Platform Replacement project, ISO staff conducted a detailed assessment of database requirements and worked with Oracle to appropriately size the target environment. This effort avoided unnecessary capital investment in excess storage capacity and reduced ongoing cost exposure, saving the Company a few million dollars. Similarly, the ISO maintains active oversight of AWS and broader cloud spend, with dedicated resources monitoring usage and aligning pricing models to demand. These efforts have also delivered several million dollars in savings by ensuring efficient use of cloud resources.

2027 Preliminary Budget Details *(cont.)*

Detailed allocation by Strategic Goal/2027 Initiatives

Goal 5: Attract, Develop, and Retain Talent: \$10.4M

- Merit and promotion increases reflecting a 3.5% annual merit adjustment and 1.0% for standard and targeted promotions and market-based adjustments (\$6.3M)
- Higher employee benefit costs, primarily driven by medical and dental trend increases and growth in participation in the Defined Contribution Benefit Plan (\$2.0M)
- Increase in employee incentive compensation aligned with market data and survey benchmarks, along with enhanced funding for employee recognition programs (\$1.3M)
- Addition of 1.5 FTEs in Human Resources, including a Business Partner to support client groups in employee engagement, change management, workforce planning, employee relations, and organizational design, as well as a partial FTE focused on developing Information Technology training programs (\$0.3M)
- Increased System Planning training investments to support the onboarding and development of newer, entry-level staff and expand proficiency in industry and technology tools (\$0.2M)
- Funding for Human Resources performance management and talent acquisition software platforms (\$0.2M)
- Increase in external recruiting fees to support hiring needs (\$0.1M)

2027 Preliminary Budget Details *(cont.)*

Detailed allocation by Strategic Goal/2027 Initiatives

Goal 3: Operational Excellence: \$9.9M

- Computer services and leasing increases driven by investments in cybersecurity (including security log monitoring and management, email threat detection, threat and risk analytics tools, performance monitoring, and AI-powered platforms); server leasing associated with data center refresh efforts; higher costs to equip staff with laptops and desktops; expanded computing and storage capacity; new or enhanced licensing for System Planning and Operations applications (including power system computer-aided design, forecasting, and simulation tools); and inflationary and vendor-driven price increases across the computer services portfolio (\$4.2M)
- Funding for 13.0 FTEs to support this goal, including System Planning resources to address technical challenges associated with the integration of inverter-based resources, perform system assessments and studies, meet NERC/NPCC requirements, support generator interconnection processes, and advance capacity auction reforms; Information and Cybersecurity roles focused on software testing automation, cloud platform infrastructure, site reliability, and strengthening energy market systems; Market Monitoring staff to address growing market complexity, advanced analytics needs, and increasingly sophisticated market behavior; and additional support roles in Finance, Human Resources, and Facilities & Security (\$2.7M)

2027 Preliminary Budget Details *(cont.)*

Detailed allocation by Strategic Goal/2027 Initiatives

Goal 3: Operational Excellence: \$9.9M *(cont.)*

- Consulting and Professional Fees increases driven by Information and Cybersecurity needs, including advisory and research services, system patching, and higher consultant utilization due to additional hours, a shift toward support over development activities, and reduced vacancies; expanded Internal Audit efforts to conduct additional system-related audits and reviews; Market Monitoring investments to enhance machine learning capabilities; and Transmission Planning support to incorporate and validate distribution data in system models (\$1.8M)
- Network Operations investments to modernize communications with local control centers, enhance tie-line telemetry, and improve ISO workforce communications (\$1.0M)
- Inflationary increases related to Information Technology training subscriptions, as well as higher travel costs for ISO workforce participation in stakeholder meetings and industry conferences (\$0.2M)

2027 Preliminary Budget Details *(cont.)*

Detailed allocation by Strategic Goal/2027 Initiatives

Goal 4: Stakeholder Engagement: \$3.8M

- Funding to establish the AC Reviewer⁽²⁾ team, including 5 FTEs and supporting professional services, to build out and manage this function (\$2.2M)
- Investment in GridUnity, a SaaS, cloud-based platform designed to accelerate energy project interconnections by automating, standardizing, and streamlining the process (\$0.9M)
- Transmission study costs, including a system-wide thermal assessment driven by FERC Order 881 requirements and OATT/Cluster Enabling Transmission Upgrade regional planning studies (\$0.3M)
- Inclusion of funding for potential LTTP study anticipated to be requested in 2027 (\$0.2M)
- Funding for 0.5 FTE in Legal to support annual RFP activities associated with LTTP requirements (\$0.2M)

(2) The buildout of the Asset Condition Reviewer group is expected to occur over the next 3 to 5 years, with FTEs added incrementally throughout this period. The 2027 Preliminary Budget includes 7 planned FTE additions, with funding provided for 5 FTEs to reflect the phased hiring approach and expected onboarding timeline.

2027 Preliminary Budget Details *(cont.)*

Detailed allocation by Strategic Goal/2027 Initiatives

Goal 2: Progress and Innovation: \$3.3M

- Funding for 10.5 FTEs across Information Technology and Advanced Technology Solutions to build out capabilities that formalize and expand the use of Artificial Intelligence and Machine Learning across ISO-NE; support the transition of internally developed advanced technologies into production environments to enhance situational awareness; and advance application migration to the cloud; additional resources are included for Planning Services to address growing demands in load forecasting, economic and environmental studies, and resource adequacy, as well as a Market Monitoring position to expand technical capacity for maintaining, enhancing, and modernizing in-house market monitoring systems (\$2.5M)
- Investment in optimization software supporting the Probabilistic Energy Adequacy Tool (PEAT) to strengthen analytical and planning capabilities (\$0.6M)
- Synchrophasor data management software to handle the high-volume, time-sensitive data generated by PMUs utilized by the ISO; this platform will provide scalable, resilient, and low-latency processing, enabling real-time grid monitoring, analysis, and decision-making (\$0.2M)

2027 Preliminary Budget Details *(cont.)*

Detailed allocation by Strategic Goal/2027 Initiatives

Goal 1: Responsive Market Designs: \$2.7M

- Information Technology computer services maintenance costs associated with GE Vernova's Grid Orchestration Software (\$1.0M)
- Increased funding to support tariff-required Net CONE (Cost of New Entry) recalculation activities (\$1.0M)
- Funding for 3.0 FTEs to support this goal, including Information Technology and Advanced Technology Solutions resources to integrate new market features into applications and tools, and Planning Services staff to support Capacity Requirement and Accreditation and Resource Qualification functions across both pre- and post-CAR implementation phases (\$0.6M)
- Market Monitoring support for energy market risk premium analysis (\$0.1M)

2027 Preliminary Budget Details *(cont.)*

Detailed allocation by Strategic Goal/2027 Initiatives

Other Increases: \$0.9M

- Insurance policy rate increase (\$0.5M)
- Increases for utility expenses due to higher expected rates at both the Windsor and Holyoke facilities (\$0.3M)
- Inflationary increases for various Building Services including physical security, janitorial, and HVAC and generator maintenance (\$0.1M)



APPENDIX 2: 5 YEAR BUDGET COMPARISON

2027 Preliminary Budget – 5 Year Comparison

	%		%		%		%		
(Budget Amounts are in Millions)	<u>2027</u>	<u>Change</u>	<u>2026</u>	<u>Change</u>	<u>2025</u>	<u>Change</u>	<u>2024</u>	<u>Change</u>	<u>2023</u>
Operating Budget Before Depr and Regulatory Fees	\$305.5	8.4%	\$281.8	8.3%	\$260.2	10.1%	\$236.3	17.0%	\$201.9
Capital Budget	45.0	5.9%	42.5	0.0%	42.5	21.4%	35.0	4.5%	33.5
Total Cash Budget	\$350.5	7.1%	\$324.3	7.1%	\$302.7	11.6%	\$271.3	15.2%	\$235.4
Operating Budget Before Depr and Regulatory Fees	\$305.5	8.4%	\$281.8	8.3%	\$260.2	10.1%	\$236.3	17.0%	\$201.9
Depreciation and Regulatory Fees (1)	49.8	3.3%	48.2	4.2%	46.2	13.8%	40.6	6.1%	38.3
Revenue Requirement Before True-up	355.3	7.7%	330.0	7.7%	306.4	10.7%	276.9	15.3%	240.2
True up	(7.6)		(15.6)		4.8		(3.0)		(14.6)
Revenue Requirement	\$347.6	10.6%	\$314.4	1.0%	\$311.2	13.6%	\$273.9	21.4%	\$225.6
Forecast – TWhs (2)	124.6	(0.0)%	124.7	0.9%	123.6	1.7%	121.5	(0.0)%	121.5
\$/KWh Rate	\$0.00279	10.6%	\$0.00252	0.1%	\$0.00252	11.7%	\$0.00225	21.4%	\$0.00186
Average Monthly Consumer Cost (3)	\$2.09		\$1.89		\$1.89		\$1.69		\$1.39

(1) The 2027 *preliminary* depreciation budget is a placeholder. The 2027 *proposed* budget will result in a detailed review of project budgets and estimated go-live dates for the impact on depreciation expenses.

(2) 2027 Forecast based on May 2026 CELT Report (Schedule 1.5.2 - Annual Net Energy - Gross (without reductions)). All other years based on CELT Report for the applicable year, which can be found on www.iso-ne.com.

(3) Based on average consumption of 750 kWh per month.

Note: Throughout the presentation some schedules may be inconsistent due to rounding.

APPENDIX 3: Forward Looking Capital Budget Spending

Forward Looking Capital Budget Spending

- The capital budget over the next five years and beyond will continue to support the Company's strategic goals with specific focus on three primary drivers :
 - nGem platform (replacing the current market system)
 - Major market and reliability related efforts
 - Cyber security & IT asset and infrastructure replacement
- In order to achieve these goals, ISO has increased the capital spending over the last few years with spending of \$42.5M in 2025, \$42.5M in 2026, and \$45.0M in 2027 with the potential to increase upwards of \$50M in future years; the capital costs are dependent on various factors, including regulatory orders and approvals and the use of professional services or internal staff
 - The ISO will continue with its current practice of providing a rolling two-year look-ahead window

nGEM Platform

- The nGEM program (next Generation Markets Management) is intended to upgrade ISO's core market software to support a system with a growing number and type of grid assets, new and more complex market features, ever multiplying security threats, and advancing IT technologies
 - GE developed nGEM in collaboration with ISO-NE, MISO, and PJM; the portion of the software upgrade unique to each ISO will be shouldered by each ISO individually
- Following the scheduled completion of the Real-time Unit Commitment (RTUC) and Coordinated Transaction Scheduling Pricing Engine (CTSPE) functions in the nGEM version of the market clearing engine (MCE) set for mid-2026, the ISO plans to continue with implementation of the next phase
 - The next phase, to be completed under the *Single Interval MCE Improvements* project, includes moving the Unit Dispatch System (UDS) and Location Marginal Pricing Calculator (LMPC) functions to the nGEM MCE; this work is expected to continue through 2028 with an estimated cost of \$13.3M

Major Market and Reliability Related Efforts

- Many of these projects are complex efforts that will have long lead times to complete with some having dependencies of stakeholder and regulatory approval
- Projects beyond 2027 (see slide 45) reflect emerging market and reliability needs not yet included in the 2027 capital plan and are presented to provide transparency into future system requirements and potential capital pressures beyond the current planning horizon, although these may fluctuate depending on stakeholder and/or FERC priorities
- Based on the complexity of the projects, the ISO expects the cost for market and reliability efforts will range from approximately \$40M - \$60M over the next five plus years

Major Market and Reliability Related Efforts *(cont.)*

- Capacity Auction Reforms – Seasonal/Accreditation (CAR-SA) effort; the transition to CAR-SA will require changes to multiple existing software systems including auditing, settlement and financial assurance, as well as new software systems to support the resource adequacy assessment process, the capacity qualification process and new auction clearing mechanisms
- Energy Management Platform (EMP) - Upgrade of the Energy Management System (EMS) and its applications, plus supporting SCADA and modeling systems to stay current with vendor-supported versions



Major Market and Reliability Related Efforts–beyond 2027

- Uncertainty Reserves - Dynamic operational reserve demand curves for incremental 10- and 30-minute reserves, and a potential new (60- or 90-minute) reserve product, to address operational uncertainties during the operating day
- Multi-interval Dispatch and Pricing (MIDAP) - Objective is to improve ISO's suite of intra-day optimization processes to perform forward-looking dispatch and pricing “in the market,” over a time horizon of several hours or possibly the balance of the day
- Efficient Storage Integration and Optimization – Includes a suite of enhancements to storage resources' participation, offer formats, and scheduling/optimization in the markets, all of which will enhance these resources' reliability and efficiency benefits to the region



Cyber Security & IT Asset and Infrastructure Replacement

- Costs for IT and cyber security initiatives will vary based on the use of internal resources versus professional services, with total spending estimated at approximately \$20M–\$40M over the next several years
- The ISO has invested heavily in cyber security maturity over the past several years and will continue doing so over the next 3–5 years; these investments enable enhanced defenses, network segmentation, and email/web filtering to improve monitoring, detection, and recovery against increasingly sophisticated threats
 - Significant focus on upgrading infrastructure to proactively mitigate future quantum computing threats to legacy cryptographic standards
- The ISO's transition to a cloud environment began in 2022 and will remain a major capital initiative over the coming years as application cloud migrations accelerate
 - Operating a modern grid with renewable and storage resources requires large-scale data processing and storage; through phased implementation, the ISO will deploy cloud computing and virtualization to support scalable computing while maintaining reliability

APPENDIX 4: 2027 Preliminary Capital Budget

Capital Budget

2027 Expenditures

Goal: Responsive Market Designs

Project	2027 Budget	Total Project Cost	Estimated Completion Date	Project Stage
. Capacity Auction Reforms*	\$6.0 M	\$8.0 M	12/2028	Conceptual Design
. EMP 3.5 Upgrade - GridOS	\$4.0 M	\$6.9 M	09/2028	Conceptual Design
. GridOS Connect	\$1.5 M	\$1.9 M	12/2027	Conceptual Design
. Resource Adequacy Assessment & Accreditation	\$1.0 M	\$1.5 M	06/2027	Conceptual Design
. Integrated Market Simulator Usability	\$1.0 M	\$1.1 M	12/2027	Conceptual Design
Total:		\$13.5 M		

*Capacity Auction Reforms may involve multiple projects, with specific details still under development.

Goal: Progress and Innovation

Project	2027 Budget	Total Project Cost	Estimated Completion Date	Project Stage
. Single Interval MCE Improvements (SIMI)	\$6.0 M	\$13.3 M	12/2028	Conceptual Design
. Advanced Technology Initiatives	\$3.0 M	\$4.0 M	12/2027	Conceptual Design
. Migration of MIS FTP to Cloud	\$0.1 M	\$0.5 M	04/2027	In Development
Total:		\$9.1 M		

Capital Budget

2027 Expenditures (cont.)

Goal: Operational Excellence

Project	2027 Budget	Total Project Cost	Estimated Completion Date	Project Stage
. Non-Project Capital Expenditures	\$7.5 M	\$7.5 M		
. MW Dependent Fuel Price Adjustment	\$1.2 M	\$2.6 M	08/2027	Conceptual Design
. TTCU Implementation for Resource Outage Coordination	\$0.2 M	\$1.1 M	05/2027	In Development
. Solar Do Not Exceed Dispatch Phase III	\$0.5 M	\$1.0 M	12/2027	Conceptual Design
. Circuit Inventory Management Platform Phase II	\$0.2 M	\$0.7 M	04/2027	Conceptual Design
. Tie Line Telemetry and PCEC Upgrade Phase II	\$0.5 M	\$0.7 M	06/2027	Conceptual Design
. Replace Employee & Pager Application	\$0.5 M	\$0.6 M	12/2027	Conceptual Design
. PowerGADS Update for Capacity Auction Reforms	\$0.5 M	\$0.5 M	06/2027	Conceptual Design
. Next-Gen Electronic Dispatch & Reliability Voice Networks	\$0.3 M	\$0.5 M	05/2027	Conceptual Design
. Enterprise Resource Planning (ERP) Enhancements 2027	\$0.5 M	\$0.5 M	12/2027	Conceptual Design
. EMT Model Repository	\$0.4 M	\$0.5 M	06/2027	Conceptual Design
. CIP Electronic Security Perimeter Network Services	\$0.2 M	\$0.3 M	09/2027	Conceptual Design
Total:		\$12.5 M		

Goal: Stakeholder Engagement

Project	2027 Budget	Total Project Cost	Estimated Completion Date	Project Stage
. Interconnection Request Tracking Upgrade	\$0.2 M	\$2.1 M	03/2027	Conceptual Design
Total:		\$0.2 M		

Capital Budget

2027 Expenditures Summary

2027 Capital Budget Expenditure Summary

Allocation Category	2027 Budget
Goal: Responsive Market Designs	\$13.5 M
Goal: Operational Excellence	\$12.5 M
Goal: Progress and Innovation	\$9.1 M
Other Emerging Work	\$8.5 M
Capital Interest	\$1.2 M
Goal: Stakeholder Engagement	\$0.2 M
Total:	\$45.0 M

APPENDIX 5: CAPITAL STRUCTURE

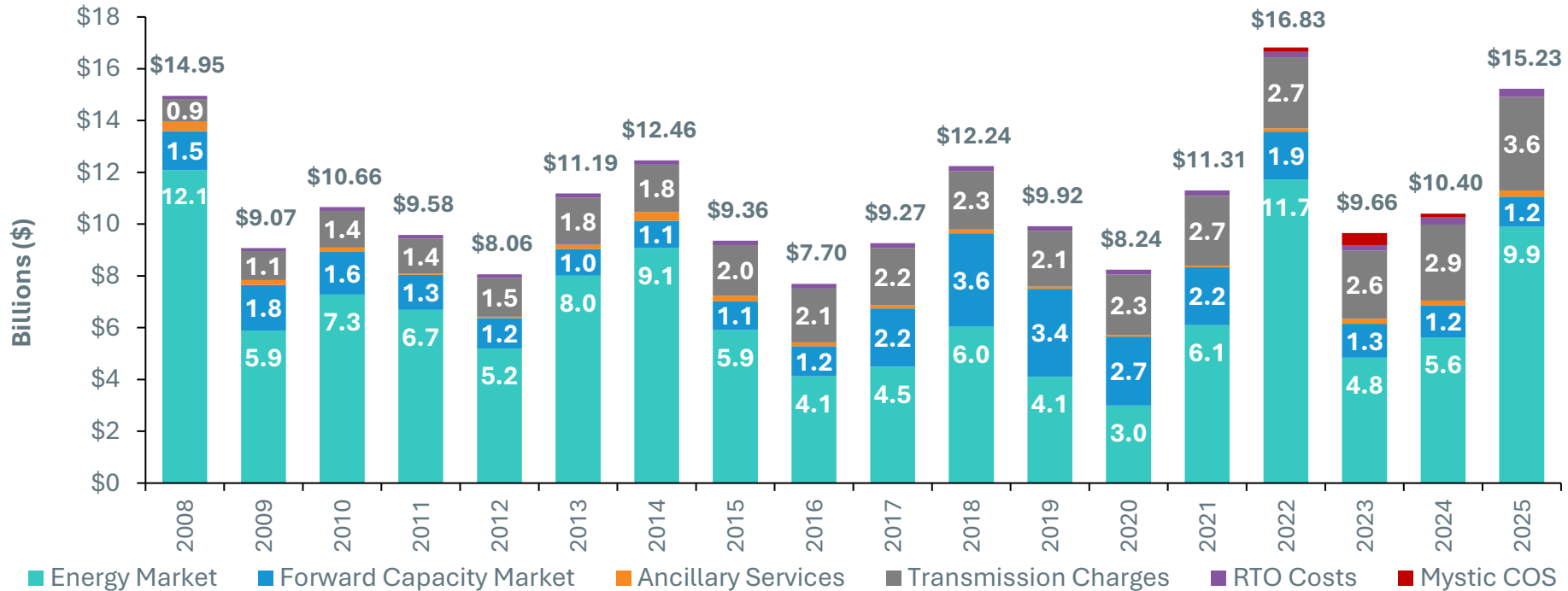
Capital Structure

- The ISO has a \$40M working capital line; the working capital line, which will expire on March 1, 2028, funds temporary operating cash flow needs arising from the lag between expenditures and revenue collections, as well as periodic annual payments that are expensed evenly throughout the year (e.g., insurance); it also mitigates cash flow risks related to lower-than-expected load and Tariff collections, timing differences in capital project spending, and fluctuations in reimbursable study deposits and withdrawals
- Capital project costs are largely funded by \$75M in Private Placement Notes that went effect in 2024, and require interest only payments until full payment of principal in 2034
- ISO closed on \$60M tax-exempt bonds in April 2026 to fund the construction of a new building on the Holyoke campus; monies have been placed into a money market account to help off-set the interest expense while funds are drawn to pay for the construction; the bonds only require interest payments until the building is fully complete, estimated Q2 2028
- For the three months ended March 31, 2026, the ISO's total weighted average cost of capital was 4.34%, excluding fees charged on the various debt financing; fees ranged from .075% to .38%

APPENDIX 6: HISTORICAL NEW ENGLAND WHOLESALE AND RETAIL ENERGY COSTS

New England Wholesale Electricity Costs*

Annual wholesale electricity costs have ranged from \$7.7 billion to \$16.8 billion



(The total costs for each year include Ancillary Services and RTO costs)

Source: ISO New England; ***2025 data is preliminary and subject to resettlement**

Note: Forward Capacity Market values shown are based on auctions held roughly three years prior to each calendar year.

New England Wholesale Electricity Costs^(a)

	2021		2022		2023		2024		2025*	
	\$ Mil.	¢/kWh	\$ Mil.	¢/kWh	\$ Mil.	¢/kWh	\$ Mil.	¢/kWh	\$ Mil.	¢/kWh
Wholesale Market Costs										
Energy (LMPs)^(b)	\$6,101	4.8	\$11,712	9.0	\$4,847	3.9	\$5,620	4.4	\$9,902	7.7
Ancillaries^(c)	\$52	0.0	\$124	0.1	\$183	0.1	\$186	0.1	\$241	0.2
Capacity^(d)	\$2,243	1.8	\$1,864	1.4	\$1,308	1.1	\$1,248	1.0	\$1,159	0.9
Subtotal	\$8,404	6.6	\$13,701	10.5	\$6,338	5.1	\$7,054	5.5	\$11,302	8.8
Transmission charges^(e)	\$2,688	2.1	\$2,739	2.1	\$2,640	2.1	\$2,934	2.3	\$3,613	2.8
RTO costs^(f)	\$216	0.2	\$214	0.2	\$214	0.2	\$274	0.2	\$314	0.2
	Mystic COS ^(h)		\$173	0.1	\$465	0.4	\$139	0.1	\$0	0.0
Total	\$11,308	8.9	\$16,828	13.0	\$9,657	7.8	\$10,401	8.2	\$15,229	11.9

(a) Average annual costs are based on the 12 months beginning January 1 and ending December 31. Costs in millions = the dollar value of the costs to New England wholesale market load servers for ISO-administered services. Cents/kWh = the value derived by dividing the dollar value (indicated above) by the real-time load obligation. These values are presented for illustrative purposes only and do not reflect actual charge methodologies. ***The wholesale values for 2025 are preliminary and subject to resettlement.**

(b) Energy values are derived from wholesale market pricing and represent the results of the Day-Ahead (DA) Market plus deviations from the DA in Real-Time. Post March 1, 2025 the DA Market total includes costs associated with the Forecast Energy Requirement.

(c) Ancillaries include first- and second-contingency Net Commitment-Period Compensation (NCPC), Forward Reserves, Real-Time Reserves, Regulation service, and a reduction due to the Marginal Loss Revenue Fund. Post Dec. 2023, this total also includes the Inventoried Energy Program (IEP). The IEP ran through Feb. 2025. Post March 1, 2025, the Forward Reserve total reflects costs associated with the Day-Ahead Ancillary Services Market.

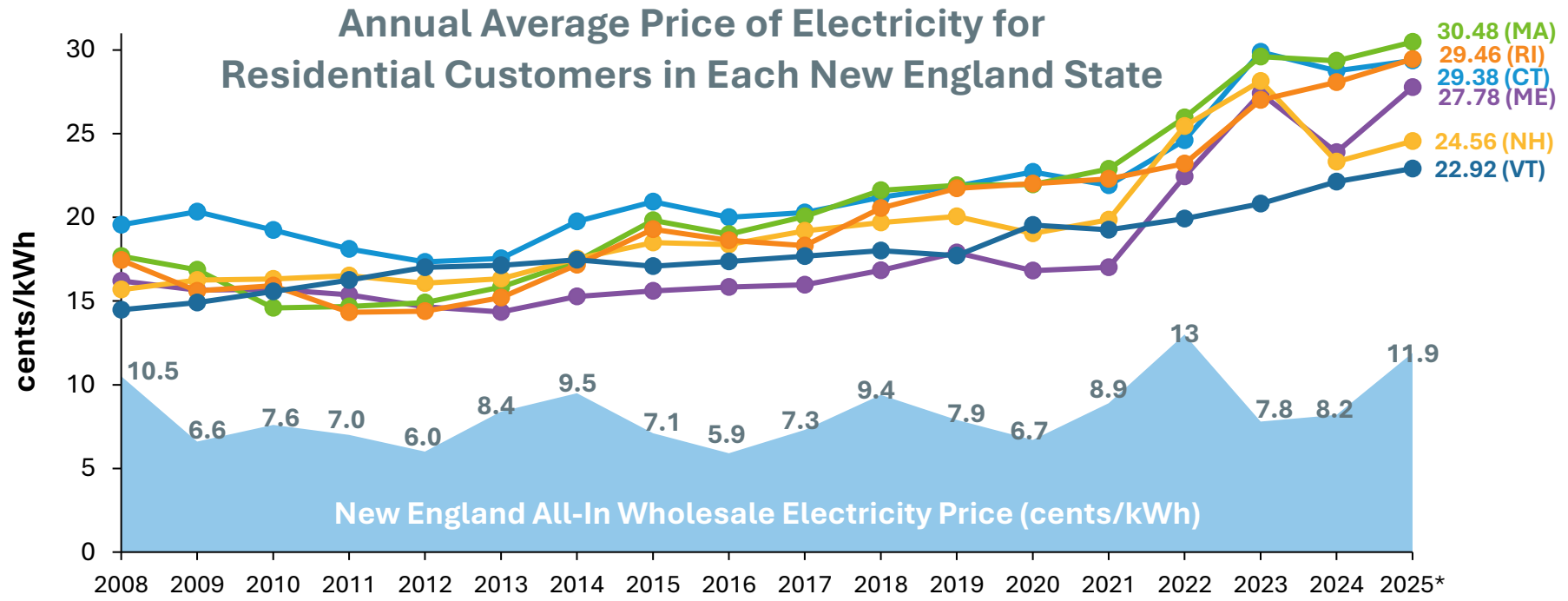
(d) Capacity charges are those associated with the Forward Capacity Market (FCM).

(e) Transmission charges reflect the collection of transmission owners' revenue requirements and tariff-based reliability services, including black start capability, voltage support, IROL CIP, and FCM reliability. In 2025, the cost of payments made to these generators for reliability services under ISO's Open Access Transmission Tariff (OATT) was \$65.4 million. Transmission charge totals for years 2010 forward reflect the refund of Schedule 1 TOUT charges to regional network load.

(g) RTO costs are the costs to operate ISO New England and are based on actual collections, as determined under Section IV of the ISO New England Inc. Transmission, Markets, and Services Tariff.

(h) Mystic Cost of Service payments were made through May 2024.

Retail Electricity Prices Follow Wholesale Prices, But Are Also Influenced by Individual State Policies



Sources: U.S. Energy Information Administration, *Electric Power Annual*, Table 2.10 Average Price of Electricity to Ultimate Customers by End-Use Sector, by State; and U.S. Energy Information Administration, *Electric Power Monthly*, Table 5.6.B Average Price of Electricity to Ultimate Customers by End-Use Sector, by State (Through Dec. 2025); the New England all-in wholesale electricity price is derived by dividing total wholesale electricity costs by real-time load obligation (presented for illustrative purposes; does not reflect actual charge methodologies) *2025 values are preliminary

APPENDIX 7: Examples of Innovation and Use of Artificial Intelligence

Improve market design fidelity and operational efficiency through advanced simulation and optimization technology

- *Integrated Market Simulator*
 - Develop a unified simulation framework that captures key real-time market and system processes
 - This framework will enable us to evaluate dynamic operating reserve demand curve, multi-interval dispatch and pricing, enhanced energy storage modeling, and market mitigation design.
- *Capacity Market Clearing Engine*
 - Build clearing engines using the latest optimization technology for the seasonal and prompt capacity markets



Increase business efficiency with agentic artificial intelligence (AI)

- *AI-Driven Workflow Automation*
 - Deploy AI agents to streamline and automate key business processes
- *Interconnection Study*
 - Facilitate interconnection request intake and initial screening, base case creation and maintenance, and support cluster study workflow
 - Accelerate interconnection timelines
 - Enhance consistency and quality control
- *Outage Coordination*
 - Use generative AI to automate outage report generation
 - Reduce manual workload
 - Enable staff to focus on higher-value engineering analysis

Reliable integration of renewable resources through advanced computing and analytics

- *Transition to risk-based operations*
 - Leverage probabilistic forecasting to quantify uncertainty from renewables
 - Develop probabilistic capacity analysis tools, providing a better picture of system capacity margin for both long-term outage coordination and short-term capacity analysis
 - Develop probabilistic transmission security assessment, evaluating transmission system risk under different renewable scenarios.

Reliable integration of renewable resources through advanced computing and analytics

- *Monitor system oscillation*
 - Deploy PMU-based oscillation source location (OSL) software in the control room operations.
 - OSL enables us to identify and mitigate system oscillations from inverter-based resources (IBR) and large data center loads.
- *Enhance Electromagnetic Transient (EMT) modeling and simulation*
 - Analyze stability challenges driven by fast dynamics of IBRs
 - Advance EMT model lifecycle management to scale adoption in operations and planning
 - Enable large-scale EMT simulation to support grid-level assessment

MEMORANDUM

TO: NEPOOL Participants Committee Members and Alternates

FROM: Rosendo Garza and Pat Gerity, NEPOOL Counsel

DATE: June 9, 2026

RE: Updates to Section IV of the Tariff

At the June 16, 2026 Participants Committee Summer Meeting, you will be asked to vote on proposed updates to Section IV.A and Section IV.B of the Tariff to clarify how the ISO's annual rates, charges, and capital budget (together, the Calendar Year Rates) will be administered if, by January 1, those Calendar Year Rates have not been authorized by the FERC or have not otherwise become effective. Included with this memorandum are the following materials:

- Attachment A: Redlined Section IV.A and IV.B Sheets
- Attachment B: ISO-NE's April 17, 2026 Presentation

BACKGROUND & OVERVIEW

Each year, in October, following the completion of the annual budget process, which includes presentations to and opportunities for feedback from stakeholders, the ISO files with the FERC under Section 205 of the Federal Power Act its Calendar Year Rates for the upcoming calendar year. The requested effective date for the Calendar Year Rates is the first day of the upcoming calendar year.¹ Tariff Section IV.A, otherwise known as the ISO's Self-Funding Tariff, establishes the calendar year rates and charges used to recover administrative expenses.² Tariff Section IV.B establishes the annual capital budget.³

As described in Attachment B, the ISO identified concerns to the Budget & Finance Subcommittee (B&F) that, if the Calendar Year Rates were not approved or otherwise effective January 1, the ISO would not have clarity or authority to continue operating on existing rates. The ISO also noted that potential government shutdowns may adversely affect FERC action on the ISO's budget and that over the past several years, the ISO has received FERC orders on its budgets later in December, creating uncertainty.⁴ To address those concerns, the ISO proposed

¹ *E.g.*, ISO New England Inc., Filing of 2026 Capital Budget and Revised Tariff Sheets for Recovery of 2026 Administrative Costs, Docket No. ER26-144 (filed Oct. 15, 2025).

² *See* Tariff § IV.A.2.1 (explaining that Section IV.A provides the “means by which the ISO collects the revenues necessary to carry out its administrative functions in each calendar year”).

³ *See* Tariff § IV.B.6.1 (describing the annual budget process).

⁴ FERC's orders approving the annual Calendar Year Rates have over the past few years arrived progressively later in December *E.g.*, Letter Order Accepting Filing of 2026 Capital Budget and Revised

revisions to Sections IV.A and IV.B to ensure that it is authorized to recover the Calendar Year Rates as of the start of the new calendar year, subject to later adjustment if and as required.

STAKEHOLDER PROCESS TO DATE

At the April 17, 2026 B&F meeting, the ISO presented its proposed revisions to Section IV.⁵ No Subcommittee member present expressed opposition to, or concerns regarding, the substance of the proposal. Following that meeting, NEPOOL Counsel identified additional clarifying revisions consistent with the intent of the ISO's proposal—namely, to ensure that the ISO is authorized and able to recover the Calendar Year Rates as of the first day of the new calendar year, including in circumstances where those rates become effective by operation of law.⁶ The ISO incorporated those clarifications in the proposed changes to Tariff Sections IV.A and IV.B, as reflected in Attachment A, and posted the revised language in advance of the June 5, 2026 B&F meeting. No Subcommittee member raised any opposition to, or concerns regarding, the proposed revisions following that posting.

The Participants Committee can use the following form of resolution for action:

RESOLVED, that the Participants Committee supports the revisions to Tariff Sections IV.A and Section IV.B, as reflected in the materials circulated to this Committee in advance of this meeting, together with [any changes agreed to by the Participants Committee at this meeting and] such non-substantive changes as may be approved by the Chair of the Budget & Finance Subcommittee.

Tariff Sheets for Recovery of 2026 Administrative Costs, Docket No. ER26-144 (Dec. 30, 2025); Letter Order Accepting Filing of 2025 Capital Budget and Revised Tariff Sheets for Recovery of 2025 Administrative Costs, Docket No. ER25-110 (Dec. 23, 2024); Letter Order Accepting Filing of 2024 Capital Budget and Revised Tariff Sheets for Recovery of 2024 Administrative Costs, Docket No. ER24-90 (Dec. 11, 2023).

⁵ See ISO New England Inc., *Continuation of Section IV Rates Absent FERC Order*, at 6–7 (Apr. 17, 2026) (providing ISO-NE's initial Tariff revisions).

⁶ 16 U.S.C. 824d(d).

SECTION IV.A
RECOVERY OF ISO ADMINISTRATIVE EXPENSES

IV.A.1 Definitions:

Whenever used in this Section IV.A, in either the singular or plural number, capitalized terms shall have the meanings specified in Section I.

IV.A.2 Purpose of Section IV.A; Adjustments to Rates

IV.A.2.1 Purpose of Section IV.A

Section IV.A of the Tariff is the means by which the ISO collects the revenues necessary to carry out its administrative functions in each calendar year, and contains rates, charges, terms and conditions for the following Services, which together encompass the functions carried out by the ISO:

- (1) Scheduling, System Control and Dispatch Service (Schedule 1 hereto);
- (2) Energy Administration Service (Schedule 2 hereto); and
- (3) Reliability Administration Service (Schedule 3 hereto).

The rates and charges for each Service during a calendar year are based on the allocated portion of that year's Revenue Requirement. "Revenue Requirement" refers to the budgeted total expense for the year as adjusted by true-ups described herein, excluding the true-up described in Section IV.A.2.2(4).

IV.A.2.2 True-Ups

(1) Schedule 2 True-Up

- (i) Each year (Year X), in determining the ISO's Revenue Requirement for the subsequent year (Year X+1), the ISO will make a true-up of the Schedule 2 portion of the Revenue Requirement for the prior year (Year X-1). Any difference between the actual Year X-1 Schedule 2 revenues and amounts budgeted for Schedule 2 revenues in the Year X-1 Revenue Requirement will be reflected in the projected Schedule 2 rates for Year X+1 as stated in paragraph (ii) below.
- (ii) In implementing the true-up adjustment for revenue differences in the volumetric portion of Schedule 2, the differences will be added to (in the case of a revenue shortfall) or subtracted from (in the case of a revenue over-recovery) the ISO's total estimated budgeted amounts for

(2) General True-Up

Each year (Year X), in determining its Revenue Requirement for Year X+1, the ISO will include in such Revenue Requirement a true-up of Year X-1's Revenue Requirement for Schedules 1, 3 and 5.

Specifically, the Revenue Requirement for Year X+1 will include deviations between collections under this Section IV.A and the ISO's actual expenses for Year X-1. For example, when filing the Revenue Requirement for 2014, the ISO will compute the total actual expenses for Schedules 1, 3 and 5 in 2012 and will compare these totals with the total charges actually collected under the Tariff for each of these Schedules during calendar year 2012. Based on these comparisons, the ISO will adjust the otherwise-projected Revenue Requirement for calendar year 2014 for one or more of Schedules 1, 3 and 5, as needed, downward or upward to reflect the actual calendar year 2012 surplus or deficit, respectively.

From these figures the ISO will calculate rates for calendar year 2014, and make a rate change filing for calendar year 2014 and succeeding years, as required, to reflect the budget amount for the applicable calendar year and the true-up calculated by means of the foregoing analysis and adjustments.

Notwithstanding the foregoing, for any instance of special purpose funding, in which funds are allocated and not to be used for any other purpose, the ISO may maintain any surplus amounts in a segregated ledger account to be applied in a future year for such specific purpose without application of the true-up mechanism described above until such time as the special purpose needs are completed, at which time the ISO will include any remaining funds in the Revenue Requirement adjustment being made pursuant to this Section (2).

(3) Indemnification

The Revenue Requirement does not reflect any amounts received by the ISO due to indemnification payments.

(4) Rollover of Existing Rates.

In the event that revised rates and charges have not become effective by January 1 regarding the calendar year rates and charges for each Service contained in Schedules 1, 2, 3, or 5 of Section IV of the Tariff, the ISO will continue to operate under the existing rates and charges in effect from the prior calendar year until revised rates and charges become effective. Upon revised rates and charges becoming effective, the ISO will implement the revised rates and charges as soon as reasonably practicable and, if subsequent year billing has commenced, the ISO will calculate what the billing and collection amounts should have been based on the revised rates and charges compared to customers' actual billings and perform a true-up.

Upon completion of the true-up, the ISO will bill any difference (through surcharges and/or refunds, as applicable), to each previously billed customer in accordance with a protocol established by the ISO with notice to the Participants Committee.

IV.A.3 Billing and Payment

IV.A.3.1 Billing Procedure:

With respect to charges under this Section IV.A., the ISO will apply the ISO Billing Policy as set forth in Exhibit ID to Section I of the Tariff.

IV.A.3.2 Working Capital Advances:

In the event that working capital financing arranged by the ISO is terminated early or repayment is accelerated (and no replacement funding has been obtained by the ISO) and Early Amortization Working Capital Charges have been assessed to Market Participants by the ISO, each month, each Market Participant shall be required to advance to the ISO an amount (each, an “Advance”) equal to the ISO’s reasonable projection of such Market Participant’s charges under the Tariff for three succeeding months. The Advances shall be held in an interest bearing account. In each succeeding month, the ISO shall adjust each Market Participant’s Advance so that, in each calendar month, each Market Participant’s Advance is equal to the ISO’s reasonable projection of such Market Participant’s charges under Section IV.A of the Tariff for such month and the next two succeeding months. If, in the reasonable judgment of the ISO, a cash deficiency is likely to occur at any time as a result of a depletion of the Advances (but not as a result of the failure of any Market Participant to pay its Advance), the ISO shall, at its option, have the right to require each Market Participant to pay the ISO its pro rata share (based on such Market Participant’s projected charges under Section IV.A of the Tariff for the instant month and the next two succeeding months compared to projected charges to all Market Participants under Section IV.A of the Tariff for the instant month and the next two succeeding months) of any additional Advances required for the ISO’s operations. If any Market Participant withdraws from the ISO or has its membership terminated, its Advance will be returned to it at the end of the month in which its withdrawal or termination is effective, provided that all of the departing Market Participant’s liabilities under the Tariff have been satisfied, and all of the other Market Participants will have their Advances adjusted accordingly.

IV.A.4 Regulatory Filings

SECTION IV.B

CAPITAL FUNDING ARRANGEMENTS

IV.B.1 Definitions:

Whenever used in this Section IV.B, in either the singular or plural number, capitalized terms shall have the meanings specified in Section I of the Tariff.

IV.B.2 Purpose of and Charges Assessed Under Section IV.B

Section IV.B is the means by which the ISO collects: (1) the revenues necessary, to the extent not obtained by the ISO through private financing, for the acquisition of capital assets required for support of the ISO's operations; (2) any remaining unamortized costs of capital items financed by the ISO in the event of termination, acceleration or other required repayment of private financing approved by the Commission pursuant to Section 204 of the Federal Power Act and entered into by the ISO (or by ISO New England Inc. as an independent system operator prior to the Operations Date) in support of capital item acquisitions; (3) the working capital amount required by the ISO in the event of termination, acceleration or required repayment of private financing approved by the Commission pursuant to Section 204 of the Federal Power Act and entered into by the ISO (or by ISO New England Inc. as an independent system operator prior to the Operations Date) (following approval thereof by the Commission pursuant to Section 204 of the Federal Power Act) to meet working capital requirements; and (4) amounts owed by the ISO in the event of termination, acceleration or required repayment of Shortfall Funding Arrangement financing approved by the Commission pursuant to Section 204 of the Federal Power Act and entered into by the ISO in support of weekly billing under the ISO New England Billing Policy.

Section IV.B comprises four charges corresponding to the four categories of costs described above.

- The Capital Funding Charge (the "CFC") will collect from the Market Participants funds for the direct purchase of capital assets if the ISO does not enter into private financing to fund these purchases or the ISO funds the purchases through interim financings and does not enter into private financing to provide long-term funding of these purchases
- The Early Amortization Charge (the "EAC") will collect from the Market Participants remaining unamortized costs of capital items financed by the ISO in the event of termination, acceleration or required repayment of private financing, or in the case of non-amortizing private financing, payment at maturity if the ISO is unable to refinance such non-amortizing private financing, entered into by the ISO (or by ISO New England Inc. as an independent system operator prior to the Operations Date) in support of capital item acquisitions, including refinancings in support of such acquisitions.

circumstance, the ISO shall immediately bill each Covered Entity and each Covered Entity shall pay, as its EPSFC, a pro rata portion of the EPSF Amount allocated in the same manner as specified in Section 5.4(c) of the ISO New England Billing Policy for payments required from Covered Entities to restore the Required Balance.

IV.B.3 Billing and Payment Billing Procedure

With respect to charges under this Section of the Tariff, the ISO will apply the ISO New England Billing Policy.

IV.B.4 Regulatory Filings

Nothing contained in this Section IV.B. shall be construed as affecting in any way the right of the ISO to file with the Commission under Section 205 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder for a change in any rates, terms and conditions, charges, classification of service, Service Agreement, rule or regulation.

Nothing contained in this Section IV.B. shall be construed as affecting in any way the ability of any Customer under Section IV.B to exercise its rights under the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

IV.B.5 Creditworthiness

The ISO will apply the creditworthiness provisions of the ISO New England Financial Assurance Policy to the Market Participants. Each Market Participant shall comply with the requirements of the ISO New England Financial Assurance Policy.

IV.B.6 Budget Process and Reports

IV.B.6.1 ISO's Capital Budgeting Process:

As part of its annual budget process, the ISO will submit to the Budget and Finance Subcommittee the ISO's proposed budget for capital expenditures. After taking into consideration the comments of the Budget and Finance Subcommittee, the ISO will submit its proposed budget for capital expenditures to the Participants Committee. The ISO shall report the results of all Participants Committee votes on the ISO's capital budget to the ISO's Board of Directors which shall have sole authority to approve the final ISO capital budget. Following such approval and at least 60 days prior to the beginning of the ISO's operating year, the ISO will file its capital budget with the Commission. All annual capital budget and

expenditure filings will be filed pursuant to, and subject to Commission review under, Section 205 of the Federal Power Act and posted on the ISO's website. In the event that the annual capital budget has not become effective by January 1 of that the operating year, the ISO will continue capital spending based on an amount no greater than (i) the prior year annual capital budget, or (ii) the proposed capital budget, whichever is less. Upon the capital budget becoming effective, the ISO will adjust any capital budget spending or priorities as necessary based on such budget, and include a summary of any necessary adjustments as part of the ISO's next quarterly filing made pursuant to Section IV.B.6.2 hereof.

IV.B.6.2 Reporting of Incurred and Forecasted Capital Costs:

Consistent with the requirements imposed by the Commission in Docket No. ER02-2153, the ISO will file quarterly reports with the Commission specifying, by project, the ISO's prior year spending on multi-year projects, year to date spending and a forecast of the next calendar year spending. In addition, the ISO will file a schedule of the unamortized costs of the ISO's funded capital expenditures at the end of the quarter and the allocation of those costs to Schedules 1, 2 and 3. Such reports will be filed within forty-five (45) days of the end of each quarter and posted on the ISO's website. All quarterly capital budget and expenditure filings will be filed pursuant to, and subject to Commission review under, Section 205 of the Federal Power Act.



Continuation of Section IV Rates Absent FERC Order

Update to Section IV – “ISO Self Funding Tariff”

John Waggoner

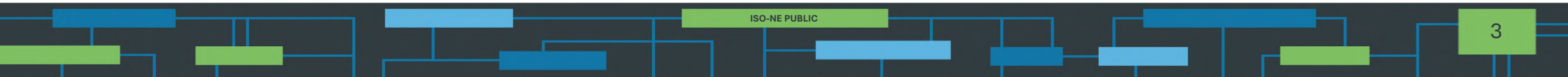
MANAGER, BUDGET & FINANCE REPORTING



- Variability in timing of ISO budget approval by FERC necessitates changes to Section IV.A and Section IV.B
 - Later-than-expected FERC approvals of the ISO's annual budget have occurred more frequently in recent years stemming from federal government shutdowns and other delays
 - The ISO currently lacks clarity on how to proceed if budget approval is stalled into the following calendar year
 - Proposed changes allow the ISO to continue operations based on existing rates and budgets pending FERC approval
- This is the introduction of the proposed changes to the Budget and Finance Subcommittee
 - Proposed changes will then be presented to the Participants Committee for a vote

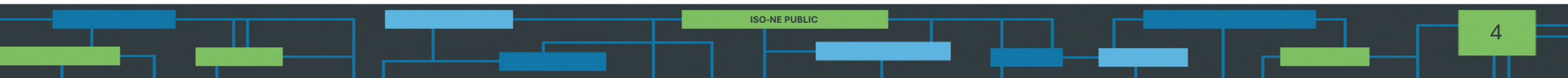
Background

- Annually, the ISO prepares an annual operating budget and capital budget for the forthcoming calendar year
 - The budget process spans several months and includes opportunities for participation and input from NEPOOL and New England state agencies
 - The ISO then makes a Section 205 filing in mid-October to establish the upcoming year's Revenue Requirement and Section IV.A rates, and the upcoming capital budget under Section IV.B
- Over the past three years, FERC's order approving the upcoming budget and rates has come later in December than prior years. Additionally, government shutdowns have added uncertainty regarding FERC's ability to issue an order, if a shutdown lasts longer than FERC funding
- Because the Section IV.A rates are based on an annual Revenue Requirement (i.e., they are calendar year rates) and Section IV.B contemplates an annual capital budget, it is unclear how the ISO would proceed, and what rates and/or spending the ISO is allowed, in the absence of a FERC order on its annual budget and tariff rate updates
 - Section IV.A rates are derived from the annual Revenue Requirement, which is a combination of the ISO's annual budget for that year and the most recently completed year's true-up, allocated by ISO's Section IV.A Schedules 1, 2, and 3 forecasted billing factors (load and transaction unit amounts). The annual Revenue Requirement includes amounts related to both prior and current year's capital spending that are depreciated/amortized based on the capital asset's in-service date and estimated useful life.



Rationale for Change

- This presentation describes proposed changes to Section IV (ISO Funding Mechanisms) of the ISO Tariff to account for the possibility that a FERC order regarding the following year's annual budget and rates may not be received by January 1
- The proposed changes to Section IV.A and IV.B provide that the ISO can continue operations based on existing rates and budgets pending a FERC order



Summary of Proposed Tariff or Manual Changes^[1]

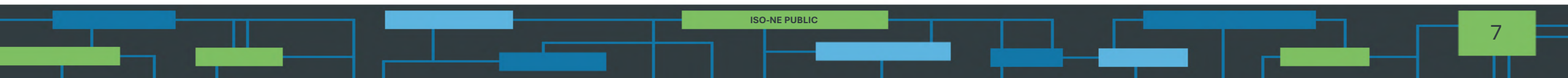
Section	Tariff or Manual Change	Reason for Change
New Paragraph: Section IV.A.2.2(4) “Procedures if Rates are not approved by January 1”	“In the event that the Commission has not issued an order regarding the calendar year rates and charges for each Service contained in Schedules 1, 2, 3 or 5 of Section IV of the Tariff by January 1 of that year, the ISO will continue to operate with the existing rates and charges in effect from the prior calendar year until the Commission has rendered a decision. Upon receiving a Commission decision, the ISO will implement the effective rates as soon as reasonably practicable and, if subsequent year billing has commenced, the ISO will calculate what the billing and collection amounts should have been based on the Commission order compared to customers’ actual billings and perform a true-up. Upon completion of the true-up, the ISO will bill any difference (increase and/or decrease), to each previously billed customer in accordance with a protocol established by the ISO with notice to the NEPOOL Budget and Finance Subcommittee.”	New paragraph adds language to state that the ISO can continue to operate using existing rates and details the procedure to be followed should billing and collection amounts need to be adjusted, if prior year existing rates were temporarily used in the new budget year due to a delay in FERC budget approval
Addition to Section IV.A.2.1 “Purpose of Section IV.A”	At end of last paragraph in section, after the word “ <i>herein</i> ” add “, <i>excluding the true-up described in Section IV.A.2.2(4)</i> ”	Adding this wording since true-up described in new paragraph IV.A.2.2(4) is not related to annual “Revenue Requirement” that is the basis for the annual rates and charges

^[1]Section IV.A and IV.B with redlines are being provided with these materials

Summary of Proposed Tariff or Manual Changes

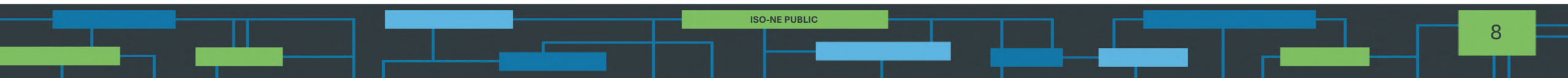
Section	Tariff or Manual Change	Reason for Change
Edit to Section IV.B.2 “Purpose of and Charges Assessed Under Section IV.B”	In the first paragraph of this section edit the word “owned” by removing the letter “n” to make the word “owed”	Grammatical edit to convey the correct meaning of the word and sentence ^[2]
Addition to: Section IV.B.6.1 “ISO’s Capital Budgeting Process”	“In the event that the Commission has not issued an order regarding the annual capital budget by January 1 of that year, the ISO will continue capital spending based on an amount no greater than (i) the prior year annual capital budget, or (ii) the pending capital budget, whichever is less. Upon receiving a Commission decision, the ISO will adjust any capital budget spending or priorities as necessary based on the Commission order, and include a summary of any necessary adjustments as part of the ISO’s next quarterly filing made pursuant to Section IV.B.6.2 hereof.”	Adding language to state that the ISO can continue capital spending based on the lower of the prior year capital budget amount or the proposed new year’s capital budget amount pending FERC approval

^[2] This is a clean-up change being made and is not related to the Section IV proposal described herein



Conclusion

- The ISO is proposing changes to Section IV.A and Section IV.B to account for potential scenarios where annual ISO rates and budget approval is not received by FERC by January 1
- Intent is to file the noted Section IV changes with the FERC no later than July 2026 and obtain approval by October 1, 2026 to allow the proposed changes to be in place for the ISO's 2027 Budget filing in mid-October

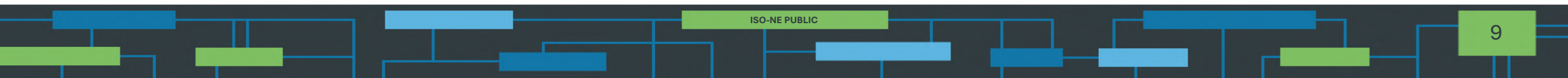


Stakeholder Schedule

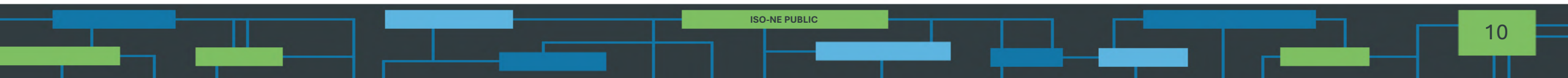
Stakeholder Committee and Date	Scheduled Project Milestone
Budget and Finance Subcommittee April 17, 2026 ^[3]	Introduce Section IV.A and IV.B proposed changes for discussion and answer any clarifying questions
Participants Committee May 7, 2026	Vote on Section IV.A and IV.B changes

^[3] If an additional Budget and Finance Subcommittee is necessary, the Subcommittee can continue discussions during the May 8, 2026 meeting and the Participants Committee can take action at the June 16-18, 2026 meeting.

Note: The intent is to file the noted Section IV changes with the FERC no later than July 2026 and obtain approval by October 1, 2026. This timing will allow the proposed changes to be in place for the ISO's 2027 Budget filing which will be filed in mid-October 2026



Questions



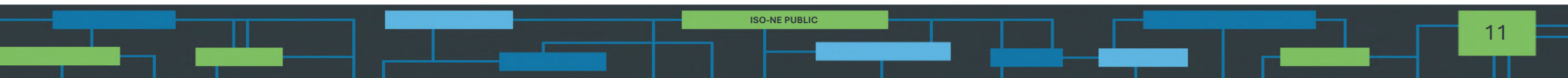
About the Presenter

John Waggoner

Manager, Budget & Finance Reporting

ISO New England

jwaggoner@iso-ne.com



MEMORANDUM

TO: NEPOOL Participants Committee Members and Alternates

FROM: Rosendo Garza, NEPOOL Counsel

DATE: June 9, 2026

RE: Proposal to Change the Pay-For-Performance Treatment of External Transactions

At its June 16, 2026 Meeting, the Participants Committee will consider the ISO’s package of revisions to change the Pay-For-Performance (PFP) treatment of external transactions (External Transactions Proposal). This memorandum provides a high-level overview of the proposal, summarizes the stakeholder process to date, and includes the following attachments:

- Attachment A: Section I.2.2 Redline Sheets
- Attachment B: Market Rule 1 Redline Sheets¹
- Attachment C: Financial Assurance Policy Redline Sheets
- Attachment D: Billing Policy Redline Sheets
- Attachment E: ISO-NE’s March 10–12, 2026 Markets Committee Presentation
- Attachment F: ISO-NE’s April 14–16, 2026 Markets Committee Presentation
- Attachment G: ISO-NE’s May 8, 2026 Budget & Finance Subcommittee Presentation
- Attachment H: ISO-NE’s June 5, 2026 Budget & Finance Subcommittee Presentation

OVERVIEW OF EXTERNAL TRANSACTIONS PROPOSAL

Under the current PFP rules, exports are relevant to PFP settlements because they may reduce the Actual Capacity Provided (ACP) of certain resources. For purposes of the ISO’s proposed revisions, there are two categories of External Transaction Sales, or exports, that are relevant: exports associated with the energy and reserves provided by a specific generator, and exports that are not associated with a specific generator. The latter category is sometimes referred to as system-backed exports, or “SBEs.” The ISO’s proposal addresses the PFP settlement consequences of exports that are not fully supported by a specific resource’s performance during a Capacity Scarcity Condition, issues that have previously been identified by the External Market Monitor (EMM) and the Internal Market Monitor (IMM) as possible areas for improvements. Attachments E and F provide additional background.

¹ After the Markets Committee’s vote, the ISO identified one edit in the Tariff redlines that the Chair and Vice-Chair deemed to be non-substantive. Specifically, the ISO modified the title of two subsections, as reflected in Attachments A and B.

MARKET RULE 1 REVISIONS AND MARKETS COMMITTEE REVIEW

In light of recommendations from the EMM and IMM, as well as stakeholder interest, the ISO proposed to create a new PFP charge quantity for SBEs. Under the proposal, the SBE quantity would be charged at the Performance Payment Rate (PPR) and removed from the number of the Capacity Balancing Ratio. Attachment B provides the proposed Tariff revisions to implement this change, and Attachment F provides additional information regarding the proposed design.

The ISO presented its initial design at the March 2026 Markets Committee meeting and provided additional detail at the April 2026 Markets Committee meeting, including information concerning export scheduling, curtailment practices, and proposed Tariff revisions. At its May 12–14, 2026 meeting, the Markets Committee voted unanimously to recommend Participants Committee support for the Market Rule 1 revisions.²

FINANCIAL ASSURANCE POLICY (FAP) AND BILLING POLICY REVISIONS AND BUDGET & FINANCE SUBCOMMITTEE (B&F) REVIEW

Given the proposed Market Rule 1 changes, the ISO also proposed conforming revisions to the FAP to address the credit risk associated with the new SBE charge. The proposed revisions would require a Designated FCM Participant with SBE transactions to include an additional SBE Financial Assurance amount in its FCM Financial Assurance Requirements. That amount would be based on the PPR, the Participant's historical SBE MW during CSCs, and historical scarcity hours for the relevant season. The ISO's updated proposal also includes two additional inputs—Monthly Export Charges and Preliminary Monthly Export Charges—to account for SBE charges already incurred but not yet fully reflected in settled invoices. The ISO also proposed related revisions to the FAP definition of Average Balancing Ratio to conform to the proposed Market Rule 1 changes.³

In addition, the ISO proposed conforming changes to the Billing Policy. Specifically, the proposed Billing Policy revisions would add SBE charges as part of the non-hourly charge in the FCM billing line. Attachment D provides the proposed Billing Policy revisions.

The ISO introduced its approach to revising the FAP at the April 2026 B&F meeting. At the following B&F meeting, the ISO presented its specific FAP redlines. At the June 2026 B&F meeting, the ISO presented the Billing Policy redlines. No Subcommittee member present at those meetings expressed opposition to, or concerns with, the proposed FAP and Billing Policy revisions.

² Abstentions were noted as follows: one in each of the Alternative Resource, End User, and Generation Sectors and eight in the Supplier Sector.

³ Although this revision is also part of the ISO's proposal to cap the Balancing Ratio, the revision is independently necessary in the External Transactions Proposal.

PARTICIPANTS COMMITTEE ACTION

For the Participants Committee to approve the External Transactions Proposal, the Markets Committee-recommended changes to Section I.2.2 and Markets Rule 1 require a 60% Vote in favor, and the proposed FAP and Billing Policy revisions require a 66.67% Vote in favor. Accordingly, the following forms of resolution, either in a single action or in separate actions, may be used for Participants Committee action on the External Transaction Proposal Tariff revisions:

RESOLVED, that the Participants Committee supports the External Transaction Proposal revisions to Tariff Section I.2.2 and Market Rule 1, as recommended by the Markets Committee at its May 2026 meeting, together with [any changes agreed to by the Participants Committee at this meeting and] such non-substantive changes as may be approved by the Chair and Vice-Chair of the Markets Committee.

RESOLVED, that the Participants Committee supports the External Transaction Proposal revisions to the ISO New England Financial Assurance Policy and the ISO New England Billing Policy, as circulated in advance of this meeting, together with [any changes agreed to by the Participants Committee at this meeting and] such non-substantive changes as may be approved by the Chair of the Budget & Finance Subcommittee.

I.2 Rules of Construction; Definitions

I.2.1. Rules of Construction:

In this Tariff, unless otherwise provided herein:

- (a) words denoting the singular include the plural and vice versa;
- (b) words denoting a gender include all genders;
- (c) references to a particular part, clause, section, paragraph, article, exhibit, schedule, appendix or other attachment shall be a reference to a part, clause, section, paragraph, or article of, or an exhibit, schedule, appendix or other attachment to, this Tariff;
- (d) the exhibits, schedules and appendices attached hereto are incorporated herein by reference and shall be construed with an as an integral part of this Tariff to the same extent as if they were set forth verbatim herein;
- (e) a reference to any statute, regulation, proclamation, ordinance or law includes all statutes, regulations, proclamations, amendments, ordinances or laws varying, consolidating or replacing the same from time to time, and a reference to a statute includes all regulations, policies, protocols, codes, proclamations and ordinances issued or otherwise applicable under that statute unless, in any such case, otherwise expressly provided in any such statute or in this Tariff;
- (f) a reference to a particular section, paragraph or other part of a particular statute shall be deemed to be a reference to any other section, paragraph or other part substituted therefor from time to time;
- (g) a definition of or reference to any document, instrument or agreement includes any amendment or supplement to, or restatement, replacement, modification or novation of, any such document, instrument or agreement unless otherwise specified in such definition or in the context in which such reference is used;
- (h) a reference to any person (as hereinafter defined) includes such person's successors and permitted assigns in that designated capacity;
- (i) any reference to "days" shall mean calendar days unless "Business Days" (as hereinafter defined) are expressly specified;
- (j) if the date as of which any right, option or election is exercisable, or the date upon which any amount is due and payable, is stated to be on a date or day that is not a Business Day, such right, option or election may be exercised, and such amount shall be deemed due and payable, on the next succeeding Business Day with the same effect as if the same was exercised or made on such date or day (without, in the case of any such payment, the payment or accrual of any interest or

other late payment or charge, provided such payment is made on such next succeeding Business Day);

- (k) words such as “hereunder,” “hereto,” “hereof” and “herein” and other words of similar import shall, unless the context requires otherwise, refer to this Tariff as a whole and not to any particular article, section, subsection, paragraph or clause hereof; and a reference to “include” or “including” means including without limiting the generality of any description preceding such term, and for purposes hereof the rule of *ejusdem generis* shall not be applicable to limit a general statement, followed by or referable to an enumeration of specific matters, to matters similar to those specifically mentioned.

I.2.2. Definitions:

In this Tariff, the terms listed in this section shall be defined as described below:

Above-Threshold Offer Segment is the total MW quantity of a Capacity Offer that is priced above the Capacity Offer Price Threshold, whether such MW quantity is delimited by only one price-quantity pair or multiple price-quantity pairs submitted as part of the Capacity Offer pursuant to Section III.15.4.1.

Active Demand Capacity Resource is one or more Demand Response Resources located within the same Dispatch Zone, that is registered with the ISO, assigned a unique resource identification number by the ISO, and participates in the Forward or Annual Capacity Market to fulfill a Market Participant’s Capacity Supply Obligation pursuant to Section III.13 or Section III.15 of Market Rule 1.

Actual Capacity Provided is the measure of capacity provided during a Capacity Scarcity Condition, as described in Section III.13.7.2.2 or Section III.15.8.2.2 of Market Rule 1.

Actual Load is the consumption at the Retail Delivery Point for the hour.

Additional Resource Blackstart O&M Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Additional Resource Specified-Term Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Participant with authority to submit a Supply Offer for the Resource. The Supply Offer will be submitted pursuant to Market Rule 1 and applicable ISO New England Manuals, and include a price and information with respect to the quantity proposed to be furnished, technical parameters for the Resource, timing and other matters. A Supply Offer is a subset of the information required in a Market Participant's Offer Data.

Supply Offer Block-Hours are Block-Hours assigned to the Lead Market Participant for each Supply Offer. Blocks of the Supply Offer in effect for each hour will be totaled to determine the quantity of Supply Offer Block-Hours for a given day. In the case that a Resource has a Real-Time unit status of "unavailable" for the entire day, that day will not contribute to the quantity of Supply Offer Block-Hours. However, if the Resource has at least one hour of the day with a unit status of "available," the entire day will contribute to the quantity of Supply Offer Block-Hours.

Synchronous Condenser is a generator that is synchronized to the grid but supplying no energy for the purpose of providing Operating Reserve or VAR or voltage support.

System-Backed Export is defined in Section III.13.7.2.A.1 and Section III.15.8.2.A.1 of Market Rule 1.

System-Backed Export Charge is calculated in accordance with Section III.13.7.2.A.2 and Section III.15.8.2.A.2 of Market Rule 1.

System Condition is a specified condition on the New England Transmission System or on a neighboring system, such as a constrained transmission element or flowgate, that may trigger Curtailment of Long-Term Firm MTF or OTF Service on the MTF or the OTF using the curtailment priority pursuant to Section II.44 of the Tariff or Curtailment of Local Long-Term Firm Point-to-Point Transmission Service on the non-PTF using the curtailment priority pursuant to Schedule 21 of the Tariff. Such conditions must be identified in the Transmission Customer's Service Agreement.

System Efficiency Needs Assessment is defined in Section 17.9 of Attachment K to the OATT.

System Efficiency Needs Scenario is an Economic Study reference scenario that is described in Section 17.2(b) of Attachment K to the OATT.

Table of Contents

III.1	Market Operations.
III.1.1	Introduction.
III.1.2	[Reserved.]
III.1.3	Definitions.
III.1.3.1	[Reserved.]
III.1.3.2	[Reserved.]
III.1.3.3	[Reserved.]
III.1.4	Requirements for Certain Transactions.
III.1.4.1	ISO Settlement of Certain Transactions.
III.1.4.2	Transactions Subject to Requirements of Section III.1.4.
III.1.4.3	Requirements for Section III.1.4 Conforming Transactions.
III.1.5	Resource Auditing.
III.1.5.1.	Claimed Capability Audits.
III.1.5.1.1	General Audit Requirements.
III.1.5.1.2	Establish Claimed Capability Audit.
III.1.5.1.3	Seasonal Claimed Capability Audits.
III.1.5.1.3.1	Seasonal DR Audits.
III.1.5.1.4	ISO-Initiated Claimed Capability Audits.
III.1.5.2.	ISO-Initiated Parameter Auditing.
III.1.5.3	Reactive Capability Audits.
III.1.6	[Reserved.]
III.1.6.1	[Reserved.]
III.1.6.2	[Reserved.]
III.1.6.3	[Reserved.]
III.1.6.4	ISO New England Manuals and ISO New England Administrative Procedures.
III.1.7	General.
III.1.7.1	Provision of Market Data to the Commission.

- III.13.6.2.5.1. Energy Market Offer Requirements.
 - III.13.6.2.5.1.1. Day-Ahead Energy Market Participation.
 - III.13.6.2.5.1.2. Real-Time Energy Market Participation.
- III.13.6.2.5.2. Additional Requirements for Demand Capacity Resources Having No Capacity Supply Obligation.
- III.13.6.3 Exporting Resources.
- III.13.6.4 ISO Requests for Energy.
 - III.13.6.4.1 Real-Time High Operating Limit.
- III.13.7 Performance, Payments and Charges in the FCM.
 - III.13.7.1 Capacity Base Payments.
 - III.13.7.1.1 Monthly Payments and Charges Reflecting Capacity Supply Obligations.
 - III.13.7.1.2 Peak Energy Rents.
 - III.13.7.1.2.1 Hourly PER Calculations.
 - III.13.7.1.2.2 Monthly PER Application.
 - III.13.7.1.3 Export Capacity.
 - III.13.7.1.4 [Reserved.]
 - III.13.7.2 Capacity Performance Payments.
 - III.13.7.2.1 Definition of Capacity Scarcity Condition.
 - III.13.7.2.2 Calculation of Actual Capacity Provided During a Capacity Scarcity Condition.
 - III.13.7.2.3 Capacity Balancing Ratio.
 - III.13.7.2.4 Capacity Performance Score.
 - III.13.7.2.5 Capacity Performance Payment Rate.
 - III.13.7.2.6 Calculation of Capacity Performance Payments.
 - [III.13.7.2.A System-Backed Export Charges.](#)
 - [III.13.7.2.A.1 System-Backed Exports.](#)
 - [III.13.7.2.A.2 Calculation of System-Backed Export Charges.](#)
 - III.13.7.3 Monthly Capacity Payment and Capacity Stop-Loss Mechanism.

- III.13.7.3.1 Monthly Stop-Loss.
- III.13.7.3.2 Annual Stop-Loss.
- III.13.7.4 Allocation of Deficient or Excess Capacity Performance Payments [and System-Backed Export Charges](#).
- III.13.7.5 Charges to Market Participants with Capacity Load Obligations.
 - III.13.7.5.1 Calculation of Capacity Charges Prior to June 1, 2022.
 - III.13.7.5.1.1 Calculation of Capacity Charges On and After June 1, 2022.
 - III.13.7.5.1.1.1 Forward Capacity Auction Charge.
 - III.13.7.5.1.1.2 Annual Reconfiguration Auction Charge.
 - III.13.7.5.1.1.3 Monthly Reconfiguration Auction Charge.
 - III.13.7.5.1.1.4 HQICC Capacity Charge.
 - III.13.7.5.1.1.5 Self-Supply Adjustment.
 - III.13.7.5.1.1.6 Intermittent Power Resource Capacity Adjustment.
 - III.13.7.5.1.1.7 Multi-Year Rate Election Adjustment.
 - III.13.7.5.1.1.8 CTR Transmission Upgrade Charge.
 - III.13.7.5.1.1.9 CTR Pool-Planned Unit Charge.
 - III.13.7.5.1.1.10 Failure to Cover Charge Adjustment.
 - III.13.7.5.2 Calculation of Capacity Load Obligation and Zonal Capacity Obligation.
 - III.13.7.5.2.1 Charges Associated with Dispatchable Asset Related Demands.
 - III.13.7.5.3 Excess Revenues.
 - III.13.7.5.4 Capacity Transfer Rights.
 - III.13.7.5.4.1 Definition and Payments to Holders of Capacity Transfer Rights.
 - III.13.7.5.4.2 Allocation of Capacity Transfer Rights.
 - III.13.7.5.4.3 Allocations of CTRs Resulting From Revised Capacity Zones.
 - III.13.7.5.4.4 Specifically Allocated CTRs Associated with Transmission Upgrades.

III.15.7.2 Resources without a Capacity Supply Obligation

III.15.7.2.1 Generating Capacity Resources without a Capacity Supply Obligation

III.15.7.2.2 Distributed Energy Capacity Resources without a Capacity Supply Obligation

III.15.7.2.3 Intermittent Power Resources without a Capacity Supply Obligation

III.15.7.2.4 [Reserved.]

III.15.7.2.5 Demand Capacity Resources without a Capacity Supply Obligation

III.15.7.3 Exporting Resources

III.15.7.4 ISO Requests for Energy

III.15.7.4.1 Real-Time High Operating Limit

III.15.8 Capacity Payments and Charges

III.15.8.1 Capacity Base Payments

III.15.8.1.1 Payments and Charges Reflecting Capacity Supply Obligations

III.15.8.1.2 Export Capacity

III.15.8.2 Capacity Performance Payments

III.15.8.2.1 Definition of Capacity Scarcity Condition

III.15.8.2.2 Calculation of Actual Capacity Provided During a Capacity Scarcity Condition

III.15.8.2.3 Capacity Balancing Ratio

III.15.8.2.4 Capacity Performance Score

III.15.8.2.5 Capacity Performance Payment Rate

III.15.8.2.6 Calculation of Capacity Performance Payments

III.15.8.2.A [System-Backed Export Charges.](#)

III.15.8.2.A.1 [System-Backed Exports.](#)

III.15.8.2.A.2 [Calculation of System-Backed Export Charges.](#)

III.15.8.3 Monthly Capacity Payment and Capacity Stop-Loss Mechanism

III.15.8.3.1 Monthly Stop-Loss

III.15.8.3.2 Annual Stop-Loss

- III.15.8.4 Allocation of Deficient or Excess Capacity Performance Payments [and System-Backed Export Charges](#)
- III.15.8.5 Charges to Market Participants with Capacity Load Obligations
 - III.15.8.5.1 Calculation of Capacity Charges
 - III.15.8.5.2 Calculation of Capacity Load Obligation and Zonal Capacity Obligation
 - III.15.8.5.3 Excess Revenues
 - III.15.8.5.4 Capacity Transfer Rights
 - III.15.8.5.4.1 Specifically Allocated CTRs Associated with Transmission Upgrades
 - III.15.8.5.4.2 Specifically Allocated CTRs for Pool-Planned Units
 - III.15.8.5.5 Annual Capacity Market Net Charge Amount
- III.15.9 Information Publication and Reporting

III.13.7. Performance, Payments and Charges in the FCM.

Revenue in the Forward Capacity Market for resources providing capacity shall be composed of Capacity Base Payments as described in Section III.13.7.1 and Capacity Performance Payments as described in Section III.13.7.2, adjusted as described in Section III.13.7.3 and Section III.13.7.4. Market Participants with a Capacity Load Obligation will be subject to charges as described in Section III.13.7.5.

In the event of a change in the Lead Market Participant for a resource that has a Capacity Supply Obligation, the Capacity Supply Obligation shall remain associated with the resource and the new Lead Market Participant for the resource shall be bound by all provisions of this Section III.13 arising from such Capacity Supply Obligation. The Lead Market Participant for the resource at the start of an Obligation Month shall be responsible for all payments and charges associated with that resource in that Obligation Month.

III.13.7.1. Capacity Base Payments.

Resources acquiring or shedding a Capacity Supply Obligation for the Obligation Month shall receive a Capacity Base Payment for the Obligation Month reflecting the payments and charges described in Section III.13.7.1.1.

III.13.7.1.1. Payments and Charges Reflecting Capacity Supply Obligations.

Each resource that has: (i) cleared in a Forward Capacity Auction, except for the portion of resources designated as Self-Supplied FCA Resources; (ii) cleared in a reconfiguration auction; or (iii) entered into a Capacity Supply Obligation Bilateral shall be entitled to a monthly payment or charge during the Capacity Commitment Period. Each monthly payment and charge listed in Section III.13.7.1.1 (a) through (d) below will be divided by the number of days in the month to derive a daily settlement value.

(a) **Forward Capacity Auction.** For a resource whose offer has cleared in a Forward Capacity Auction, the monthly capacity payment shall equal the product of its cleared capacity and the Capacity Clearing Price in the Capacity Zone in which the resource is located as adjusted by applicable indexing for resources with additional Capacity Commitment Period elections pursuant to Section III.13.1.1.2.2.4 in the manner described below. For a resource that has elected to have the Capacity Clearing Price and the Capacity Supply Obligation apply for more than one Capacity Commitment Period, payments associated with the Capacity Supply Obligation and Capacity Clearing Price (indexed using the Handy-Whitman Index of Public Utility Construction Costs in effect as of December 31 of the year preceding the Capacity Commitment Period) shall continue to apply after the Capacity Commitment Period associated

curtailment as described in Section III.8.3, a Real-Time demand reduction shall also be calculated for intervals in which the associated Demand Response Resource or Demand Response Distributed Energy Resource Aggregation does not receive a non-zero Dispatch Instruction; (2) in the case of a Demand Response Asset or Distributed Energy Resource associated with a Demand Response Distributed Energy Resource Aggregation that is on a forced or scheduled curtailment as described in Section III.8.3, the minuend in the calculation described in Section III.8.4 shall be the unadjusted Demand Response Baseline of the Demand Response Asset or Distributed Energy Resource associated with a Demand Response Distributed Energy Resource Aggregation; and (3) the resulting MWhs of reduction, other than the MWhs associated with Net Supply, shall be increased by average avoided peak transmission and distribution losses.

III.13.7.2.3 Capacity Balancing Ratio.

For each five-minute interval in which a Capacity Scarcity Condition exists, the ISO shall calculate a Capacity Balancing Ratio using the following formula:

$$(\text{Load} + \text{Reserve Requirement}) / \text{Total Capacity Supply Obligation}$$

(a) If the Capacity Scarcity Condition is a result of a violation of the Minimum Total Reserve Requirement such that the associated system-wide Reserve Constraint Penalty Factor pricing applies, then the terms used in the formula above shall be calculated as follows:

Load = the total amount of Actual Capacity Provided (excluding applicable Real-Time Reserve Designations) from all resources in the New England Control Area during the interval (with the Actual Capacity Provided of Energy Efficiency measures being zero, as specified in Section III.13.7.2.2(c)(i)) minus the sum of all absolute net System-Backed Export values calculated in accordance with the formulas set forth in Section III.13.7.2.A.2 in the New England Control Area during the interval.

Reserve Requirement = the Minimum Total Reserve Requirement during the interval.

Total Capacity Supply Obligation = the total amount of Capacity Supply Obligations in the New England Control Area during the interval, excluding the Capacity Supply Obligations associated with Energy Efficiency measures.

(b) If the Capacity Scarcity Condition is a result of a violation of the Ten-Minute Reserve Requirement such that the associated system-wide Reserve Constraint Penalty Factor pricing applies, then the terms used in the formula above shall be calculated as follows:

Load = the total amount of Actual Capacity Provided (excluding applicable Real-Time Reserve Designations) from all resources in the New England Control Area during the interval (with the Actual Capacity Provided of Energy Efficiency measures being zero, as specified in Section III.13.7.2.2(c)(i)) minus the sum of all absolute net System-Backed Export values calculated in accordance with the formulas set forth in Section III.13.7.2.A.2 in the New England Control Area during the interval.

Reserve Requirement = the Ten-Minute Reserve Requirement during the interval.

Total Capacity Supply Obligation = the total amount of Capacity Supply Obligations in the New England Control Area during the interval, excluding the Capacity Supply Obligations associated with Energy Efficiency measures.

(c) If the Capacity Scarcity Condition is a result of a violation of the Zonal Reserve Requirement such that the associated Reserve Constraint Penalty Factor pricing applies, then the terms used in the formula above shall be calculated as follows:

Load = the total amount of Actual Capacity Provided (excluding applicable Real-Time Reserve Designations) from all resources in the Capacity Zone during the interval plus the net amount of energy imported into the Capacity Zone from outside the New England Control Area during the interval (but not less than zero) (with the Actual Capacity Provided of Energy Efficiency measures being zero, as specified in Section III.13.7.2.2(c)(i)) minus the sum of all absolute net System-Backed Export values calculated in accordance with the formulas set forth in Section III.13.7.2.A.2 in the Capacity Zone during the interval.

Reserve Requirement = the Zonal Reserve Requirement minus any reserve support coming into the Capacity Zone over the internal transmission interface.

Total Capacity Supply Obligation = the total amount of Capacity Supply Obligations in the Capacity Zone during the interval, excluding the Capacity Supply Obligations associated with Energy Efficiency measures.

(d) The following provisions shall be used to determine the applicable Capacity Balancing Ratio where more than one of the conditions described in subsections (a), (b), and (c) apply in a Capacity Zone.

(i) In any Capacity Zone subject to Reserve Constraint Penalty Factor pricing associated with both the Minimum Total Reserve Requirement and the Ten-Minute Reserve Requirement, but not the Zonal Reserve Requirement, the Capacity Balancing Ratio shall be calculated as described in Section III.13.7.2.3(a) for resources in that Capacity Zone.

(ii) In any Capacity Zone subject to Reserve Constraint Penalty Factor pricing associated with both the Ten-Minute Reserve Requirement and the Zonal Reserve Requirement, but not the Minimum Total Reserve Requirement, the Capacity Balancing Ratio for resources in that Capacity Zone shall be the higher of the Capacity Balancing Ratio calculated as described in Section III.13.7.2.3(b) and the Capacity Balancing Ratio calculated as described in Section III.13.7.2.3(c).

(iii) In any Capacity Zone subject to Reserve Constraint Penalty Factor pricing associated with the Minimum Total Reserve Requirement and the Zonal Reserve Requirement (regardless of whether the Capacity Zone is also subject to Reserve Constraint Penalty Factor pricing associated with the Ten-Minute Reserve Requirement), the Capacity Balancing Ratio for resources in that Capacity Zone shall be the higher of the Capacity Balancing Ratio calculated as described in Section III.13.7.2.3(a) and the Capacity Balancing Ratio calculated as described in Section III.13.7.2.3(c).

III.13.7.2.4 Capacity Performance Score.

Each resource, whether or not it has a Capacity Supply Obligation, will be assigned a Capacity Performance Score for each five-minute interval in which a Capacity Scarcity Condition exists in the Capacity Zone in which the resource is located. A resource's Capacity Performance Score for the interval shall equal the resource's Actual Capacity Provided during the interval (with the Actual Capacity Provided of Energy Efficiency measures being zero, as specified in Section III.13.7.2.2(c)(i)) minus the product of the resource's Capacity Supply Obligation (which for this purpose shall not be less than zero) and the applicable Capacity Balancing Ratio; provided, however, that for an On-Peak Demand Resource or a Seasonal Peak Demand Resource, the Capacity Supply Obligation associated with any Energy Efficiency measures shall be excluded from the calculation of the resource's Capacity Performance Score. The resulting Capacity Performance Score may be positive, zero, or negative.

III.13.7.2.5 Capacity Performance Payment Rate.

For the three Capacity Commitment Periods beginning June 1, 2018 and ending May 31, 2021, the Capacity Performance Payment Rate shall be \$2000/MWh. For the three Capacity Commitment Periods beginning June 1, 2021 and ending May 31, 2024, the Capacity Performance Payment Rate shall be \$3500/MWh. For the Capacity Commitment Period beginning on June 1, 2024 and ending on May 31, 2025, the Capacity Performance Payment Rate shall be \$5455/MWh. For the Capacity Commitment Period beginning on June 1, 2025 and ending on May 31, 2026 and thereafter, the Capacity Performance Payment Rate shall be \$9337/MWh. The ISO shall review the Capacity Performance Payment Rate in the stakeholder process as needed and shall file with the Commission a new Capacity Performance Payment Rate if and as appropriate.

III.13.7.2.6 Calculation of Capacity Performance Payments.

For each resource, whether or not it has a Capacity Supply Obligation, the ISO shall calculate a Capacity Performance Payment for each five-minute interval in which a Capacity Scarcity Condition exists in the Capacity Zone in which the resource is located. A resource's Capacity Performance Payment for an interval shall equal the resource's Capacity Performance Score for the interval multiplied by the Capacity Performance Payment Rate. The resulting Capacity Performance Payment for an interval may be positive or negative.

III.13.7.2.A System-Backed Export Charges.

III.13.7.2.A.1 System-Backed Exports.

A System-Backed Export is an External Transaction submitted in accordance with Section III.1.10.7 or Section III.1.10.7.A to export internal energy out of the New England Control Area by a Market Participant in the Real-Time Energy Market: (1) that is not associated with a generator; or (2) for External Transactions associated with a generator, for which the megawatt amount of the External Transaction sale(s) associated with the generator is greater than the sum of the resource's energy output plus the resource's Reserve Quantity For Settlement.

III.13.7.2.A.2 Calculation of System-Backed Export Charges.

For each five-minute interval in which a Capacity Scarcity Condition exists, the ISO shall calculate a System-Backed Export Charge: (1) for External Transactions associated with a generator, for each resource that submitted an External Transaction sale in the Real-Time Energy Market corresponding with

the five-minute interval; and (2) for External Transactions not associated with a generator, for each Market Participant that submitted an External Transaction sale in the Real-Time Energy Market corresponding with the five-minute interval. For each five-minute interval, the System-Backed Export Charge shall be equal to the net System-Backed Export value, calculated in accordance with the formulas set forth below, multiplied by the Capacity Performance Payment Rate, as defined in Section III.13.7.2.5.

For External Transactions associated with a generator,

net System-Backed Export value = the lesser of (the energy output of the generator in the interval + the Reserve Quantity for Settlement of the generator in the interval – the hourly integrated delivered MW for the External Transaction sale(s) associated with the generator) or 0

System-Backed Export Charge = net System-Backed Export value × Capacity Performance Payment Rate

For External Transactions not associated with a generator,

net System-Backed Export value = the lesser of (the hourly integrated delivered MW for the External Transaction purchase(s) of the Market Participant – the hourly integrated delivered MW for the External Transaction sale(s) of the Market Participant) or 0

System-Backed Export Charge = net System-Backed Export value × Capacity Performance Payment Rate

Unless otherwise expressly stated, a System-Backed Export Charge shall not be treated as a Capacity Performance Payment under the Tariff.

III.13.7.3 Monthly Capacity Payment and Capacity Stop-Loss Mechanism.

Each resource's Monthly Capacity Payment for an Obligation Month, which may be positive or negative, shall be the sum of the resource's Capacity Base Payment for the Obligation Month plus the sum of the resource's Capacity Performance Payments for all five-minute intervals in the Obligation Month, except as provided in Section III.13.7.3.1 and Section III.13.7.3.2 below.

III.13.7.3.1 Monthly Stop-Loss.

If the sum of the resource's Capacity Performance Payments (excluding any Capacity Performance Payments associated with Actual Capacity Provided above the resource's Capacity Supply Obligation in any interval) for all five-minute intervals in the Obligation Month is negative, the amount subtracted from the resource's Capacity Base Payment for the Obligation Month will be limited to an amount equal to the product of the applicable Forward Capacity Auction Starting Price multiplied by the resource's Capacity Supply Obligation for the Obligation Month (or, in the case of a resource subject to a multi-year Capacity Commitment Period election made in a Forward Capacity Auction prior to the ninth Forward Capacity

III.13.7.4 Allocation of Deficient or Excess Capacity Performance Payments and System-Backed Export Charges.

For each type of Capacity Scarcity Condition as described in Section III.13.7.2.1 and for each Capacity Zone, the ISO shall allocate deficient or excess Capacity Performance Payments and System-Backed Export Charges as described in subsections (a) and (b) below. Where more than one type of Capacity Scarcity Condition applies, then the provisions below shall be applied in proportion to the duration of each type of Capacity Scarcity Condition.

(a) If the sum of all Capacity Performance Payments and System-Backed Export Charges to all resources subject to the Capacity Scarcity Condition in the Capacity Zone in an Obligation Month is positive, the deficiency will be charged to resources in proportion to each such resource's Capacity Supply Obligation for the Obligation Month, excluding any resources subject to the stop-loss mechanism described in Section III.13.7.3 for the Obligation Month and excluding any resource, or portion thereof, consisting of Energy Efficiency measures. If the charge described in this Section III.13.7.4(a) causes a resource to reach the stop-loss limit described in Section III.13.7.3, then the stop-loss cap described in Section III.13.7.3 will be applied to that resource, and the remaining deficiency will be further allocated to other resources in the same manner as described in this Section III.13.7.4(a).

(b) If the sum of all Capacity Performance Payments and System-Backed Export Charges to all resources subject to the Capacity Scarcity Condition in the Capacity Zone in an Obligation Month is negative, the excess will be credited to all such resources (excluding any resource, or portion thereof, consisting of Energy Efficiency measures) in proportion to each resource's Capacity Supply Obligation for the Obligation Month. For a resource subject to the stop-loss mechanism described in Section III.13.7.3 for the Obligation Month, any such credit shall be reduced (though not to less than zero) by the amount not charged to the resource as a result of the application of the stop-loss mechanism described in Section III.13.7.3, and the remaining excess will be further allocated to other resources in the same manner as described in this Section III.13.7.4(b).

III.13.7.5. Charges to Market Participants with Capacity Load Obligations.

III.13.7.5.1. Calculation of Capacity Charges Prior to June 1, 2022.

The provisions in this subsection apply to charges associated with Capacity Commitment Periods beginning prior to June 1, 2022. A load serving entity with a Capacity Load Obligation as of the end of the Obligation Month shall be subject to a charge equal to the product of: (a) its Capacity Load Obligation

in the Capacity Zone; and (b) the applicable Net Regional Clearing Price. The Net Regional Clearing Price is defined as the sum of the total payments as defined in Section III.13.7 paid to resources with Capacity Supply Obligations in the Capacity Zone (excluding any capacity payments and charges made for Capacity Supply Obligation Bilaterals and excluding any Capacity Performance Payments), and including any applicable export charges or credits as determined pursuant to Section III.13.7.1.3 divided by the sum of all Capacity Supply Obligations (excluding (i) the quantity of capacity subject to Capacity Supply Obligation Bilaterals and (ii) the quantity of capacity clearing as Self-Supplied FCA Resources) assumed by resources in the zone. A load serving entity with a Capacity Load Obligation as of the end of the Obligation Month may also receive a failure to cover credit equal to the product of: (a) its Capacity Load Obligation in the Capacity Zone, and; (b) the sum of all failure to cover charges in the Capacity Zone calculated pursuant to Section III.13.3.4(b), divided by total Capacity Load Obligation in the Capacity Zone.

III.13.7.5.1.1. Calculation of Capacity Charges On and After June 1, 2022.

The provisions in this subsection apply to charges associated with Capacity Commitment Periods beginning on or after June 1, 2022. For purposes of this Section III.13.7.5.1.1, Capacity Zone costs calculated for a Capacity Zone that contains a nested Capacity Zone shall exclude the Capacity Zone costs of the nested Capacity Zone. A Market Participant with a Capacity Load Obligation on any day of the Obligation Month shall be subject to the following charges and adjustments. Each charge and adjustment described in subsection (b) of Sections III.13.7.5.1.1.1 through III.13.7.5.1.1.9 will be divided by the number of days in the month to derive a daily settlement value.

III.13.7.5.1.1.1 Forward Capacity Auction Charge.

The FCA charge, for each Capacity Zone, is: (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) Capacity Zone FCA Costs divided by Zonal Capacity Obligation.

Where

Capacity Zone FCA Costs, for each Capacity Zone, are the Total FCA Costs multiplied by the Zonal Peak Load Allocator and divided by the Total Peak Load Allocator.

Total FCA Costs are the sum of, for all Capacity Zones, (i) Capacity Supply Obligations in each zone (the total obligation awarded to or shed by resources in the Forward Capacity Auction process for the Obligation Month in the zone, excluding any obligations awarded to Intermittent Power Resources that are the basis for the Intermittent Power Resource Capacity Adjustment

III.15. Annual Capacity Market.

(a) Annual Capacity Market Overview.

The ISO shall administer an annual market for capacity (Annual Capacity Market) in accordance with the provisions of this Section III.15. For each one-year period from June 1 through May 31, starting with the period June 1, 2028 to May 31, 2029, for which Capacity Supply Obligations are assumed and payments are made in the Annual Capacity Market (“Capacity Commitment Period”), the ISO shall conduct an Annual Capacity Auction in accordance with the provisions of Section III.15.4 to procure the amount of capacity needed in the New England Control Area and in each modeled Capacity Zone during the Capacity Commitment Period, as determined in accordance with the provisions of Section III.12. To be eligible to assume a Capacity Supply Obligation for a Capacity Commitment Period through the Annual Capacity Auction, a resource must have Qualified Capacity resulting from the Annual Capacity Auction qualification process in accordance with the provisions of Sections III.15.2 and III.15.3. Obligations associated with the Annual Capacity Market may be traded during ISO-administered Monthly Reconfiguration Auctions and monthly bilateral transactions, in accordance with Section III.15.5 and Section III.15.6, respectively. The obligations of resources with Capacity Supply Obligations resulting from the Annual Capacity Auction, Monthly Reconfiguration Auctions, and monthly bilateral transactions are set forth in Section III.15.7. Payments and charges resulting from participation in the Annual Capacity Market, Monthly Reconfiguration Auctions, and bilateral transactions, [as well as Capacity Performance Payments and System-Backed Export Charges](#), are set forth in Section III.15.8. The publication of auction-related information is set forth in Section III.15.9.

(b) Capacity Auction Calendar.

Beginning with the timeline for the Capacity Commitment Period beginning on June 1, 2028, and for each Capacity Commitment Period thereafter, the ISO shall publish a calendar of dates and deadlines for the administration of the Capacity Market, with the dates and deadlines being consistent for each Annual Capacity Auction cycle. The Capacity Auction Calendar shall include specific dates and deadlines for all such Capacity Market dates and deadlines defined in this Section III.15 and related Tariff provisions. The following defines several milestone dates and deadlines.

- (1) the Qualification Data Submission Deadline for the Annual Capacity Auction shall occur during the month of February;

(2) the Capacity Demonstration Deadline for the Annual Capacity Auction shall occur during the month of April; and

(3) the Annual Capacity Auction shall occur during the month of May.

(c) Modification of Capacity Auction Calendar.

The ISO may, on a prospective basis, reasonably revise any date or deadline in the Capacity Auction Calendar with written notice of such revision to each Governance Participant in the manner specified in Section 17.11(b) of the Participants Agreement prior to the occurrence of the date or deadline being revised. In the event a Market Participant fails to meet a deadline in the Capacity Auction Calendar for submission of information or data, the ISO shall extend such deadline for that Market Participant upon receipt of an order from the Commission granting the Market Participant's request for a waiver of such deadline for good cause shown. In no event shall a date or deadline be extended, prospectively by the ISO or retroactively by filing of a Market Participant, should doing so interfere with the ISO's effective administration of the Capacity Market.

(d) Effectiveness for the 2028-2029 Capacity Commitment Period and Thereafter.

The provisions of this Section III.15 are effective for the Capacity Commitment Period that runs from June 1, 2028 through May 31, 2029 and all Capacity Commitment Periods thereafter. Unless otherwise expressly stated, the provisions of this Section III.15 are not applicable to the Forward Capacity Market. Section III.13, addressing the administration of the Forward Capacity Market shall continue to be effective for Capacity Commitment Periods through May 31, 2028. Unless otherwise expressly stated, the provisions of Section III.13 are not applicable to the Annual Capacity Market, Monthly Reconfiguration Auctions and monthly bilateral transactions addressed in this Section III.15 of Market Rule 1.

III.15.8. Capacity Payments and Charges.

Revenue in the Annual Capacity Market for resources providing capacity shall be composed of Capacity Base Payments as described in Section III.15.8.1 and Capacity Performance Payments as described in Section III.15.8.2, adjusted as described in Section III.15.8.3 and Section III.15.8.4. Market Participants with a Capacity Load Obligation shall be subject to charges as described in Section III.15.8.5.

In the event of a change in the Lead Market Participant for a resource that has a Capacity Supply Obligation, the Capacity Supply Obligation shall remain associated with the resource and the new Lead Market Participant for the resource shall be bound by all provisions of this Section III.15 arising from such Capacity Supply Obligation. The Lead Market Participant for the resource at the start of an Obligation Month shall be responsible for all payments and charges associated with that resource in that Obligation Month.

III.15.8.1. Capacity Base Payments.

Resources acquiring or shedding a Capacity Supply Obligation for the Obligation Month shall receive a Capacity Base Payment for the Obligation Month reflecting the payments and charges described in Section III.15.8.1.1.

III.15.8.1.1. Payments and Charges Reflecting Capacity Supply Obligations.

Each resource that has: (i) cleared in an Annual Capacity Auction, except for the portion of resources designated as Self-Supplied Capacity Resources; (ii) cleared in a reconfiguration auction; or (iii) entered into a Capacity Supply Obligation Bilateral shall be entitled to a monthly payment or charge during the Capacity Commitment Period. Each monthly payment and charge listed in Section III.15.8.1.1 (a) through (d) below will be divided by the number of days in the month to derive a daily settlement value.

(a) **Annual Capacity Auction.** For a resource whose offer has cleared in an Annual Capacity Auction, the monthly capacity payment shall equal the product of its cleared capacity and the Capacity Clearing Price in the Capacity Zone in which the resource is located as adjusted by applicable indexing for resources with additional Capacity Commitment Period elections pursuant to Section III.13.1.1.2.2.4 in the manner described below. For a resource that elected to have the Capacity Clearing Price and the Capacity Supply Obligation apply for more than one Capacity Commitment Period, payments associated with the Capacity Supply Obligation and Capacity Clearing Price (indexed using the Handy-Whitman Index of Public Utility Construction Costs in effect as of December 31 of the year preceding the Capacity Commitment Period) shall continue to apply after the Capacity Commitment Period associated with the

Baseline of the Demand Response Asset or Distributed Energy Resource associated with the Demand Response Distributed Energy Resource Aggregation; and (3) the resulting MWhs of reduction, other than the MWhs associated with Net Supply, shall be increased by average avoided peak transmission and distribution losses.

III.15.8.2.3. Capacity Balancing Ratio.

For each five-minute interval in which a Capacity Scarcity Condition exists, the ISO shall calculate a Capacity Balancing Ratio using the following formula:

$$(\text{Load} + \text{Reserve Requirement}) / \text{Total Capacity Supply Obligation}$$

(a) If the Capacity Scarcity Condition is a result of a violation of the Minimum Total Reserve Requirement such that the associated system-wide Reserve Constraint Penalty Factor pricing applies, then the terms used in the formula above shall be calculated as follows:

Load = the total amount of Actual Capacity Provided (excluding applicable Real-Time Reserve Designations) from all resources in the New England Control Area during the interval (with the Actual Capacity Provided of Energy Efficiency measures being zero, as specified in Section III.15.8.2.2(c)(i)) [minus the sum of all absolute net System-Backed Export values calculated in accordance with the formulas set forth in Section III.15.8.2.A.2 in the New England Control Area during the interval.](#)

Reserve Requirement = the Minimum Total Reserve Requirement during the interval.

Total Capacity Supply Obligation = the total amount of Capacity Supply Obligations in the New England Control Area during the interval, excluding the Capacity Supply Obligations associated with Energy Efficiency measures.

(b) If the Capacity Scarcity Condition is a result of a violation of the Ten-Minute Reserve Requirement such that the associated system-wide Reserve Constraint Penalty Factor pricing applies, then the terms used in the formula above shall be calculated as follows:

Load = the total amount of Actual Capacity Provided (excluding applicable Real-Time Reserve Designations) from all resources in the New England Control Area during the interval (with the Actual Capacity Provided of Energy Efficiency measures being zero, as specified in Section III.15.8.2.2(c)(i))

minus the sum of all absolute net System-Backed Export values calculated in accordance with the formulas set forth in Section III.15.8.2.A.2 in the New England Control Area during the interval.

Reserve Requirement = the Ten-Minute Reserve Requirement during the interval.

Total Capacity Supply Obligation = the total amount of Capacity Supply Obligations in the New England Control Area during the interval, excluding the Capacity Supply Obligations associated with Energy Efficiency measures.

(c) If the Capacity Scarcity Condition is a result of a violation of the Zonal Reserve Requirement such that the associated Reserve Constraint Penalty Factor pricing applies, then the terms used in the formula above shall be calculated as follows:

Load = the total amount of Actual Capacity Provided (excluding applicable Real-Time Reserve Designations) from all resources in the Capacity Zone during the interval plus the net amount of energy imported into the Capacity Zone from outside the New England Control Area during the interval (but not less than zero) (with the Actual Capacity Provided of Energy Efficiency measures being zero, as specified in Section III.15.8.2.2(c)(i)) minus the sum of all absolute net System-Backed Export values calculated in accordance with the formulas set forth in Section III.15.8.2.A.2 in the Capacity Zone during the interval.

Reserve Requirement = the Zonal Reserve Requirement minus any reserve support coming into the Capacity Zone over the internal transmission interface.

Total Capacity Supply Obligation = the total amount of Capacity Supply Obligations in the Capacity Zone during the interval, excluding the Capacity Supply Obligations associated with Energy Efficiency measures.

(d) The following provisions shall be used to determine the applicable Capacity Balancing Ratio where more than one of the conditions described in subsections (a), (b), and (c) apply in a Capacity Zone.

(i) In any Capacity Zone subject to Reserve Constraint Penalty Factor pricing associated with both the Minimum Total Reserve Requirement and the Ten-Minute Reserve Requirement, but not the Zonal Reserve Requirement, the Capacity Balancing Ratio shall be calculated as described in Section III.15.8.2.3(a) for resources in that Capacity Zone.

(ii) In any Capacity Zone subject to Reserve Constraint Penalty Factor pricing associated with both the Ten-Minute Reserve Requirement and the Zonal Reserve Requirement, but not the Minimum Total Reserve Requirement, the Capacity Balancing Ratio for resources in that Capacity Zone shall be the higher of the Capacity Balancing Ratio calculated as described in Section III.15.8.2.3(b) and the Capacity Balancing Ratio calculated as described in Section III.15.8.2.3(c).

(iii) In any Capacity Zone subject to Reserve Constraint Penalty Factor pricing associated with the Minimum Total Reserve Requirement and the Zonal Reserve Requirement (regardless of whether the Capacity Zone is also subject to Reserve Constraint Penalty Factor pricing associated with the Ten-Minute Reserve Requirement), the Capacity Balancing Ratio for resources in that Capacity Zone shall be the higher of the Capacity Balancing Ratio calculated as described in Section III.15.8.2.3(a) and the Capacity Balancing Ratio calculated as described in Section III.15.8.2.3(c).

III.15.8.2.4. Capacity Performance Score.

Each resource, whether or not it has a Capacity Supply Obligation, will be assigned a Capacity Performance Score for each five-minute interval in which a Capacity Scarcity Condition exists in the Capacity Zone in which the resource is located. A resource's Capacity Performance Score for the interval shall equal the resource's Actual Capacity Provided during the interval (with the Actual Capacity Provided of Energy Efficiency measures being zero, as specified in Section III.15.8.2.2(c)(i)) minus the product of the resource's Capacity Supply Obligation (which for this purpose shall not be less than zero) and the applicable Capacity Balancing Ratio; provided, however, that for an On-Peak Demand Capacity Resource or a Seasonal Peak Demand Capacity Resource, the Capacity Supply Obligation associated with any Energy Efficiency measures shall be excluded from the calculation of the resource's Capacity Performance Score. The resulting Capacity Performance Score may be positive, zero, or negative.

III.15.8.2.5. Capacity Performance Payment Rate.

The Capacity Performance Payment Rate shall be \$9337/MWh. The ISO shall review the Capacity Performance Payment Rate in the stakeholder process as needed and shall file with the Commission a new Capacity Performance Payment Rate if and as appropriate.

III.15.8.2.6. Calculation of Capacity Performance Payments.

For each resource, whether or not it has a Capacity Supply Obligation, the ISO shall calculate a Capacity Performance Payment for each five-minute interval in which a Capacity Scarcity Condition exists in the Capacity Zone in which the resource is located. A resource's Capacity Performance Payment for an interval shall equal the resource's Capacity Performance Score for the interval multiplied by the Capacity Performance Payment Rate. The resulting Capacity Performance Payment for an interval may be positive or negative.

III.15.8.2.A System-Backed Export Charges.

III.15.8.2.A.1 System-Backed Exports.

A System-Backed Export is an External Transaction submitted in accordance with Section III.1.10.7 or Section III.1.10.7.A to export internal energy out of the New England Control Area by a Market Participant in the Real-Time Energy Market: (1) that is not associated with a generator; or (2) for External Transactions associated with a generator, for which the megawatt amount of the External Transaction sale(s) associated with the generator is greater than the sum of the resource's energy output plus the resource's Reserve Quantity For Settlement.

III.15.8.2.A.2 Calculation of System-Backed Export Charges.

For each five-minute interval in which a Capacity Scarcity Condition exists, the ISO shall calculate a System-Backed Export Charge: (1) for External Transactions associated with a generator, for each resource that submitted an External Transaction sale in the Real-Time Energy Market corresponding with the five-minute interval; and (2) for External Transactions not associated with a generator, for each Market Participant that submitted an External Transaction sale in the Real-Time Energy Market corresponding with the five-minute interval. For each five-minute interval, the System-Backed Export Charge shall be equal to the net System-Backed Export value, calculated in accordance with the formulas set forth below, multiplied by the Capacity Performance Payment Rate, as defined in Section III.15.8.2.5.

For External Transactions associated with a generator,

net System-Backed Export value = the lesser of (the energy output of the generator in the interval + the Reserve Quantity for Settlement of the generator in the interval – the hourly integrated delivered MW for the External Transaction sale(s) associated with the generator) or 0

System-Backed Export Charge = net System-Backed Export value × Capacity Performance Payment Rate

For External Transactions not associated with a generator,

net System-Backed Export value = the lesser of (the hourly integrated delivered MW for the External Transaction purchase(s) of the Market Participant – the hourly integrated delivered MW for the External Transaction sale(s) of the Market Participant) or 0

System-Backed Export Charge = net System-Backed Export value × Capacity Performance Payment Rate

Unless otherwise expressly stated, a System-Backed Export Charge shall not be treated as a Capacity Performance Payment under the Tariff.

III.15.8.3. Monthly Capacity Payment and Capacity Stop-Loss Mechanism.

Each resource's Monthly Capacity Payment for an Obligation Month, which may be positive or negative, shall be the sum of the resource's Capacity Base Payment for the Obligation Month plus the sum of the resource's Capacity Performance Payments for all five-minute intervals in the Obligation Month, except as provided in Section III.15.8.3.1 and Section III.15.8.3.2 below.

III.15.8.3.1. Monthly Stop-Loss.

If the sum of the resource's Capacity Performance Payments (excluding any Capacity Performance Payments associated with Actual Capacity Provided above the resource's Capacity Supply Obligation in any interval) for all five-minute intervals in the Obligation Month is negative, the amount subtracted from the resource's Capacity Base Payment for the Obligation Month shall be limited to an amount equal to the product of the applicable Capacity Auction Offer Price Cap multiplied by the resource's Capacity Supply Obligation for the Obligation Month.

III.15.8.3.2. Annual Stop-Loss.

(a) For each Obligation Month, the ISO shall calculate a stop-loss amount equal to:

$$\text{MaxCSO} \times [3 \text{ months} \times (\text{ACAcp} - \text{ACA}_{\text{sp}}) - (12 \text{ months} \times \text{ACAcp})]$$

Where:

MaxCSO = the resource's highest monthly Capacity Supply Obligation in the Capacity Commitment Period to date.

ACAcp = the Capacity Clearing Price for the relevant Annual Capacity Auction.

ACAsp = the Annual Capacity Auction Offer Price Cap for the relevant Annual Capacity Auction.

(b) For each Obligation Month, the ISO shall calculate each resource's cumulative Capacity Performance Payments as the sum of the resource's Capacity Performance Payments for all months in the Capacity Commitment Period to date, with those monthly amounts limited as described in Section III.15.8.3.1.

(c) If the sum of the resource's Capacity Performance Payments (excluding any Capacity Performance Payments associated with Actual Capacity Provided above the resource's Capacity Supply Obligation in any interval) for all five-minute intervals in the Obligation Month is negative, the amount subtracted from the resource's Capacity Base Payment for the Obligation Month shall be limited to an amount equal to the difference between the stop-loss amount calculated as described in Section III.15.8.3.2(a) and the resource's cumulative Capacity Performance Payments as described in Section III.15.8.3.2(b).

III.15.8.4. Allocation of Deficient or Excess Capacity Performance Payments and System-Backed Export Charges.

For each type of Capacity Scarcity Condition as described in Section III.15.8.2.1 and for each Capacity Zone, the ISO shall allocate deficient or excess Capacity Performance Payments and System-Backed Export Charges as described in subsections (a) and (b) below. Where more than one type of Capacity Scarcity Condition applies, then the provisions below shall be applied in proportion to the duration of each type of Capacity Scarcity Condition.

(a) If the sum of all Capacity Performance Payments and System-Backed Export Charges to all resources subject to the Capacity Scarcity Condition in the Capacity Zone in an Obligation Month is positive, the deficiency will be charged to resources in proportion to each such resource's Capacity Supply Obligation for the Obligation Month, excluding any resources subject to the stop-loss mechanism described in Section III.15.8.3 for the Obligation Month and excluding any resource, or portion thereof, consisting of Energy Efficiency measures. If the charge described in this Section III.15.8.4(a) causes a resource to reach the stop-loss limit described in Section III.15.8.3, then the stop-loss cap described in Section III.15.8.3 will be applied to that resource, and the remaining deficiency will be further allocated to other resources in the same manner as described in this Section III.15.8.4(a).

(b) If the sum of all Capacity Performance Payments [and System-Backed Export Charges](#) to all resources subject to the Capacity Scarcity Condition in the Capacity Zone in an Obligation Month is negative, the excess will be credited to all such resources (excluding any resource, or portion thereof, consisting of Energy Efficiency measures) in proportion to each resource's Capacity Supply Obligation for the Obligation Month. For a resource subject to the stop-loss mechanism described in Section III.15.8.3 for the Obligation Month, any such credit shall be reduced (though not to less than zero) by the amount not charged to the resource as a result of the application of the stop-loss mechanism described in Section III.15.8.3, and the remaining excess will be further allocated to other resources in the same manner as described in this Section III.15.8.4(b).

III.15.8.5. Charges to Market Participants with Capacity Load Obligations.

III.15.8.5.1. Calculation of Capacity Charges.

For purposes of this Section III.15.8.5.1, Capacity Zone costs calculated for a Capacity Zone that contains a nested Capacity Zone shall exclude the Capacity Zone costs of the nested Capacity Zone. A Market Participant with a Capacity Load Obligation on any day of the Obligation Month shall be subject to the following charges and adjustments. Each charge and adjustment described in rate component (b) of Sections III.15.8.5.1.1 through III.15.8.5.1.8 shall be divided by the number of days in the month to derive a daily settlement value.

III.15.8.5.1.1. Annual Capacity Auction Charge.

The ACA charge, for each Capacity Zone, is: (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) Capacity Zone ACA Costs divided by Zonal Capacity Obligation.

Where:

Capacity Zone ACA Costs, for each Capacity Zone, are the Total ACA Costs multiplied by the Zonal Peak Load Allocator and divided by the Total Peak Load Allocator.

Total ACA Costs are the sum of, for all Capacity Zones, Capacity Supply Obligations in each zone (the total obligation awarded to resources in the Annual Capacity Auction process for the Obligation Month in the zone, excluding any obligations awarded to Intermittent Power Resources that are the basis for the Intermittent Power Resource Capacity Adjustment specified in Section III.15.8.5.1.5) multiplied by the applicable clearing price from the auction in which the obligation was awarded to the resource.

EXHIBIT IA

ISO NEW ENGLAND FINANCIAL ASSURANCE POLICY

Table of Contents

Overview

- I. GROUPS REGARDED AS SINGLE MARKET PARTICIPANTS
- II. MARKET PARTICIPANTS' REVIEW AND CREDIT LIMITS
 - A. Minimum Criteria for Market Participation
 - 1. Information Disclosure
 - 2. Risk Management
 - 3. Communications
 - 4. Capitalization
 - 5. Additional Eligibility Requirements
 - 6. Prior Uncured Defaults
 - B. Proof of Financial Viability for Applicants
 - C. Ongoing Review and Credit Ratings
 - 1. Rated and Credit Qualifying Market Participants
 - 2. Unrated Market Participants
 - 3. Information Reporting Requirements for Market Participants
 - D. Market Credit Limits
 - 1. Market Credit Limit for Non-Municipal Market Participants
 - a. Market Credit Limit for Rated Non-Municipal Market Participants
 - b. Market Credit Limit for Unrated Non-Municipal Market Participants
 - 2. Market Credit Limit for Municipal Market Participants
 - E. Transmission Credit Limits
 - 1. Transmission Credit Limit for Rated Non-Municipal Market Participants
 - 2. Transmission Credit Limit for Unrated Non-Municipal Market Participants
 - 3. Transmission Credit Limit for Municipal Market Participants
 - F. Credit Limits for FTR-Only Customers
 - G. Total Credit Limit
- III. MARKET PARTICIPANTS' REQUIREMENTS
 - A. Determination of Financial Assurance Obligations

- B. Unsettled FTR Financial Assurance
- C. Settlement Financial Assurance
- D. Consequences of Failure to Satisfy FTR Financial Assurance Requirements
- VII. ADDITIONAL PROVISIONS FOR FORWARD CAPACITY MARKETS
 - A. FCM Delivery Financial Assurance
 - 1. FCM Delivery Financial Assurance Calculation
 - 2. Corporate Liquidity Assessment Methodology
 - 3. FCM Affiliate Guaranties
 - B. Non-Commercial Capacity
 - 1. FCM Deposit
 - 2. Non-Commercial Capacity in Forward Capacity Auctions
 - a. Non-Commercial Capacity Participating in a Forward Capacity Auction Up To and Including the Eighth Forward Capacity Auction
 - b. Non-Commercial Capacity Participating in the Ninth Forward Capacity Auction and All Forward Capacity Auctions Thereafter
 - 3. Return of Non-Commercial Capacity Financial Assurance
 - 4. Credit Test Percentage Consequences for Provisional Members
 - C. [SBE Financial Assurance](#)~~[Reserved for Future Use]~~
 - D. Loss of Capacity and Forfeiture of Non-Commercial Capacity Financial Assurance
 - E. Composite FCM Transactions
 - F. Transfer of Capacity Supply Obligations
 - 1. Transfer of Capacity Supply Obligations in Reconfiguration Auctions
 - 2. Transfer of Capacity Supply Obligations in Capacity Supply Obligation Bilaterals
 - 3. Financial Assurance for Annual Reconfiguration Transactions
 - 4. Substitution Auctions
- VIII. [Reserved]
- IX. THIRD-PARTY CREDIT PROTECTION
- X. ACCEPTABLE FORMS OF FINANCIAL ASSURANCE
 - A. Shares of Registered or Private Mutual Funds in a Shareholder Account
 - B. Letter of Credit
 - 1. Risk Mitigation Draws
 - 2. Requirements for Banks
 - 3. Form of Letter of Credit

EXHIBIT IA
ISO NEW ENGLAND FINANCIAL ASSURANCE POLICY

Overview

The procedures and requirements set forth in this ISO New England Financial Assurance Policy shall govern all Applicants, all Market Participants and all Non-Market Participant Transmission Customers. Capitalized terms used in the ISO New England Financial Assurance Policy shall have the meaning specified in Section I.

The purpose of the ISO New England Financial Assurance Policy is (i) to establish minimum criteria for participation in the New England Markets; (ii) to establish a financial assurance policy for Market Participants and Non-Market Participant Transmission Customers that includes commercially reasonable credit review procedures to assess the financial ability of an Applicant, a Market Participant or a Non-Market Participant Transmission Customer to pay for service transactions under the Tariff and to pay its share of the ISO expenses, including amounts under Section IV of the Tariff, and including any applicable Participant Expenses; (iii) to set forth the requirements for alternative forms of security that will be deemed acceptable to the ISO and consistent with commercial practices established by the Uniform Commercial Code that protect the ISO and the Market Participants against the risk of non-payment by other, defaulting Market Participants or by Non-Market Participant Transmission Customers; (iv) to set forth the conditions under which the ISO will conduct business in a nondiscriminatory way so as to avoid the possibility of failure of payment for services rendered under the Tariff; and (v) to collect amounts past due, to collect amounts payable upon billing adjustments, to make up shortfalls in payments, to suspend Market Participants and Non-Market Participant Transmission Customers that fail to comply with the terms of the ISO New England Financial Assurance Policy, to terminate the membership of defaulting Market Participants and to terminate service to defaulting Non-Market Participant Transmission Customers.

I. GROUPS REGARDED AS SINGLE MARKET PARTICIPANTS

In the case of a group of Entities that are treated as a single Market Participant pursuant to Section 4.1 of the Second Restated NEPOOL Agreement (the “RNA”), the group members shall be deemed to have elected to be jointly and severally liable for all debts to Market Participants, PTOs, Non-Market Participant Transmission Customers, NEPOOL and the ISO of any of the group members. For the purposes of the ISO New England Financial Assurance Policy, the term “Market Participant” shall, in the case of a group of members that are treated as a single Market Participant pursuant to Section 4.1 of the RNA, be deemed to refer to the group of members as a whole, and any financial assurance provided

or to the allocation applied by the ISO in the case of an Affiliate that provided no determination) such that the sum is no greater than \$50 million.

III. MARKET PARTICIPANTS' REQUIREMENTS

Each Market Participant that provides the ISO with financial assurance pursuant to this Section III must provide the ISO with financial assurance in one of the forms described in Section X below and in an amount equal to the amount required in order to avoid suspension under Section III.B below (the "Market Participant Financial Assurance Requirement"). A Market Participant's Market Participant Financial Assurance Requirement shall remain in effect as provided herein until the later of (a) 150 days after termination of the Market Participant's membership or (b) the end date of all FTRs awarded to the Market Participant and the final satisfaction of all obligations of the Market Participant providing that financial assurance; provided, however that financial assurances required by the ISO New England Financial Assurance Policy related to potential billing adjustments chargeable to a terminated Market Participant shall remain in effect until such billing adjustment request is finally resolved in accordance with the provisions of the ISO New England Billing Policy. Furthermore and without limiting the generality of the foregoing, (i) any portion of any financial assurance provided under the ISO New England Financial Assurance Policy that relates to a Disputed Amount shall not be terminated or returned prior to the resolution of such dispute, even if the Market Participant providing such financial assurance is terminated or voluntarily terminates its MPSA and otherwise satisfies all of its obligations to the ISO and (ii) the ISO shall not return or permit the termination of any financial assurance provided under the ISO New England Financial Assurance Policy by a Market Participant that has terminated its membership or been terminated to the extent that the ISO determines in its reasonable discretion that that financial assurance will be required under the ISO New England Financial Assurance Policy with respect to an unsettled liability or obligation owing from that Market Participant.

A Market Participant that knows that it is not satisfying its Market Participant Financial Assurance Requirement shall notify the ISO immediately of that fact.

A. Determination of Financial Assurance Obligations

For purposes of the ISO New England Financial Assurance Policy:

- (i) a Market Participant's "Hourly Requirements" at any time will be the sum of (x) the Hourly Charges (excluding Daily FCM Charges) for such Market Participant that have been invoiced but not paid (which amount shall not be less than \$0), plus (y) the Hourly

Charges (excluding Daily FCM Charges) for such Market Participant that have been settled but not invoiced, plus (z) the Hourly Charges (excluding Daily FCM Charges) for such Market Participant that have been cleared but not settled which amount shall be calculated by the Hourly Charges Estimator. The Hourly Charges Estimator (which amount shall not be less than \$0) shall be determined by the following formula:

$$\text{Hourly Charges Estimator} = \sum_{i=t-n+1}^t \text{HC}_i \times \text{LMP ratio} \times 1.15$$

Where:

t = The last day that such Market Participant's Hourly Charges (excluding Daily FCM Charges) are fully settled;

n = The number of days that such Market Participant's Day-Ahead Energy has been cleared but not settled;

HC = The Hourly Charges (excluding Daily FCM Charges) for such Market Participant for a fully settled day; and

LMP ratio = The average Day-Ahead Prices at the New England Hub over the period of cleared but not settled n days divided by the average Day-Ahead Prices at the New England Hub over the period of most recent fully settled n days. For purposes of this Section III.A.(i), the "New England Hub" shall mean the Hub located in Western and Central Massachusetts referred to as .H.INTERNAL_HUB;

- (ii) A Market Participant's "Daily FCM Requirements" at any time will be the sum of (x) the Daily FCM Charges that have been invoiced but not paid (which amount shall not be less than \$0), plus (y) the Daily FCM Charges that have been settled but not invoiced, plus (z) the Daily FCM Charges for such Market Participant that have been incurred but not settled which amount shall be calculated by the Daily FCM Obligation Estimator. The Daily FCM Obligation Estimator (which amount shall not be less than \$0) shall be determined by the following formula:

$$\text{Daily FCM Obligation Estimator} = \text{MAX}(\text{FCM\_Daily\_Credit\_CM} \times \text{NDAY\_CM} + \text{FCM\_Daily\_Credit\_PM} \times \text{NDAY\_PM} + \text{FCM\_Charge\_LD} \times \text{NDAY\_P2} \times \text{FCA\_Price\_Ratio}, 0)$$

Where:

FCM_Daily_Credit_CM is the portion of the Daily FCM Charges that corresponds to Capacity Supply Obligations for the Market Participant in the current month;

FCM_Daily_Credit_PM is the portion of the Daily FCM Charges that corresponds to Capacity Supply Obligations for the Market Participant in the month preceding the current month;

NDAY_CM is the number of days in the current month within the period from the last day the Daily FCM Charges have been settled to the current day (when financial assurance is assessed);

NDAY_PM is the number of days in the month preceding the current month within the period from the last day of the Daily FCM Charges have been settled to the current day (when financial assurance is assessed);

FCM_Charge_LD is the portion of the Daily FCM Charges that corresponds to Capacity Load Obligations for the Market Participant from the last day the Daily FCM Charges have been settled; and

NDAY_P2 is the number of days from the last day the Daily FCM Charges have been settled to the current day (when financial assurance is assessed) plus 2.

The FCA_Price_Ratio shall be calculated as the weighted average of the Capacity Clearing Prices for the Rest-of-Pool Capacity Zone for the relevant Capacity Commitment Periods divided by the Capacity Clearing Price for the Rest-of-Pool Capacity Zone corresponding to the Capacity Commitment Period that contains the last day the Daily FCM Charges have been settled, as determined by the following formula:

$$\text{FCA\_Price\_Ratio} = (((\text{Clearing Price\_CCP}_n \times \text{NDAY\_P2\_CCP}_n) + (\text{Clearing Price\_CCP}_{n+1} \times \text{NDAY\_P2\_CCP}_{n+1})) / \text{NDAY\_P2}) / (\text{Clearing Price\_CCP}_n)$$

Where:

Clearing Price_CCP_n is the Capacity Clearing Price for the Rest-of-Pool Capacity Zone corresponding to the Capacity Commitment Period that contains the last day that the Daily FCM Charges have been settled;

Clearing Price_CCP_{n+1} is the Capacity Clearing Price for the Rest-of-Pool Capacity Zone for the Capacity Commitment Period following CCP_n;

NDAY_P2_CCP_n is number of days in the CCP_n within NDAY_P2; and

NDAY_P2_CCP_{n+1} is number of days in the CCP_{n+1} within NDAY_P2.

- (iii) a Market Participant's "Non-Hourly Requirements" at any time will be determined by averaging that Market Participant's Non-Hourly Charges but not include: (A) the amount due from or to such Market Participant for FTR transactions, (B) any amounts due from such Market Participant for the Forward Capacity Market [or System-Backed Export transactions](#), (C) any amounts due under Section 14.1 of the RNA, (D) any amounts due for NEPOOL GIS API Fees, and (E) the amount of any Qualification Process Cost Reimbursement Deposit (including the annual true-up of that amount) due from such Market Participant) over the two most recently invoiced calendar months; provided that such Non-Hourly Requirements shall in no event be less than zero;
- (iv) a Market Participant's "Transmission Requirements" at any time will be determined by averaging that Market Participant's Transmission Charges over the two most recently invoiced calendar months; provided that such Transmission Requirements shall in no event be less than \$0;
- (v) a Market Participant's Virtual Requirements at any time will equal the amount of all unsettled Increment Offers and Decrement Bids submitted by such Market Participant at such time (which amount of unsettled Increment Offers and Decrement Bids will be calculated by the ISO according to a methodology approved from time to time by the NEPOOL Budget and Finance Subcommittee and posted on the ISO's website);
- (vi) a Market Participant's "Financial Assurance Obligations" at any time will be equal to the sum at such time of:
 - a. such Market Participant's Hourly Requirements; plus
 - b. such Market Participant's Daily FCM Requirements; plus
 - c. such Market Participant's Virtual Requirements; plus
 - d. such Market Participant's Non-Hourly Requirements times 2.50 (subject to Section X.D with respect to Provisional Members); plus
 - e. such Market Participant's "FTR Financial Assurance Requirements" under Section VI below; plus
 - f. such Market Participant's "FCM Financial Assurance Requirements" under Section VII below; plus

- g. such Market Participant's "IEP Financial Assurance Requirement" under Section III.D below; plus
 - h. the amount of any Disputed Amounts received by such Market Participant; and
- (vii) a Market Participant's "Transmission Obligations" at any time will be such Market Participant's Transmission Requirements times 2.50.

To the extent that the calculations of the components of a Market Participant's Financial Assurance Obligations (excluding FTR Financial Assurance Requirements) as described above produce positive and negative values, such components may offset each other; provided, however, that a Market Participant's Financial Assurance Obligations shall never be less than zero.

B. Credit Test Calculations and Allocation of Financial Assurance, Notice and Suspension from the New England Markets

1. Credit Test Calculations and Allocation of Financial Assurance

The financial assurance provided by a Market Participant shall be applied as described in this Section.

- (a) "Market Credit Test Percentage" is equal to a Market Participant's Financial Assurance Obligations (excluding FTR Financial Assurance Requirements) divided by the sum of its Market Credit Limit and any financial assurance allocated as described in subsection (d) below.
- (b) "FTR Credit Test Percentage" is equal to a Market Participant's FTR Financial Assurance Requirements divided by any financial assurance allocated as described in subsection (d) below.
- (c) "Transmission Credit Test Percentage" is equal to a Market Participant's Transmission Obligations divided by the sum of its Transmission Credit Limit and any financial assurance allocated as described in subsection (d) below.
- (d) A Market Participant's financial assurance shall be allocated as follows:
 - (i) financial assurance shall be first allocated so as to ensure that the Market Participant's Market Credit Test Percentage is no greater than 100%;
 - (ii) any financial assurance that remains after the allocation described in subsection (d) (i) shall be allocated so as to ensure that the Market Participant's FTR Credit Test Percentage is no greater than 100%;

Designated FTR Participant the balance of such financial assurance after all such overdue obligations have been satisfied.

VII. ADDITIONAL PROVISIONS FOR FORWARD CAPACITY MARKETS

Any Lead Market Participant, including any Provisional Member that is a Lead Market Participant, transacting in the Forward Capacity Market that is otherwise required to provide additional financial assurance under the ISO New England Financial Assurance Policy, [and any Market Participant with System-Backed Export transactions](#) (each a “Designated FCM Participant”), is required to provide additional financial assurance meeting the requirements of Section X below in the amounts described in this Section VII (such amounts being referred to in the ISO New England Financial Assurance Policy as the “FCM Financial Assurance Requirements”). If the Lead Market Participant for a Resource changes, then the new Lead Market Participant for the Resource shall become the Designated FCM Participant.

A. FCM Delivery Financial Assurance

Each Designated FCM Participant that has a Capacity Supply Obligation for the Capacity Commitment Period associated with the sixteenth Forward Capacity Auction or any Capacity Commitment Period thereafter, shall be subject to a “Corporate Liquidity Assessment” as described in this Section VII.A to determine its FCM Delivery Financial Assurance.

1. FCM Delivery Financial Assurance Calculation

A Designated FCM Participant must include, for the Capacity Supply Obligation of each resource in its portfolio other than the Capacity Supply Obligation associated with any Energy Efficiency measures, FCM Delivery Financial Assurance in the calculation of its FCM Financial Assurance Requirements under the ISO New England Financial Assurance Policy. If a Designated FCM Participant’s FCM Delivery Financial Assurance is negative, it will be used to reduce the Designated FCM Participant’s Financial Assurance Obligations (excluding FTR Financial Assurance Requirements), but not to less than zero.

FCM Delivery Financial Assurance is calculated according to the following formula for a Designated FCM Participant that has a Capacity Supply Obligation up to and including the end of the Capacity Commitment Period associated with the fifteenth Forward Capacity Auction:

$$\text{FCM Delivery Financial Assurance} = [\text{DFAMW} \times \text{PE} \times \max[(\text{ABR} - \text{CWAP}), 0.1] \times \text{SF}] - \text{IMC} - \text{MCC}$$

FCM Delivery Financial Assurance is calculated according to the following applicable formula for a Designated FCM Participant that has a Capacity Supply Obligation commencing at the beginning of the Capacity Commitment Period associated with the sixteenth Forward Capacity Auction and every Capacity Commitment Period thereafter. The applicable FCM Delivery Financial Assurance formula is determined by the results of a Corporate Liquidity Assessment and is limited by the operation of the applicable stop-loss mechanisms as set forth in Market Rule 1 (including those that may apply in the next Capacity Commitment Period).

Corporate Liquidity Assessment Result: Low Risk

$$\text{FCM Delivery Financial Assurance} = [\text{DFAMW} \times \text{PE} \times \max[(\text{ABR} - \text{CWAP}), 0.1] \times \text{SF}] - \text{IMC} - \text{MCC}$$

Corporate Liquidity Assessment Result: Medium Risk

$$\text{FCM Delivery Financial Assurance} = [\text{DFAMW} \times \text{PE} \times \max[(\text{ABR} - \text{CWAP}), 0.1] \times \text{SF}] - \text{IMC} - \text{MCC} - \text{Peak Monthly Stop-loss} \times \max[(\text{ABR} - \text{CWAP}), 0.1]$$

Corporate Liquidity Assessment Result: High Risk

$$\begin{aligned} \text{FCM Delivery Financial Assurance} = & [\text{DFAMW} \times \text{PE} \times \max[(\text{ABR} - \text{CWAP}), 0.1] \times \text{SF}] - \text{IMC} - \text{MCC} - \text{Peak Monthly Stop-loss} \times \max[(\text{ABR} - \text{CWAP}), 0.1] \\ & - \text{Second Largest Monthly Stop-loss} \times \max[(\text{ABR} - \text{CWAP}), 0.1] \end{aligned}$$

Where:

MCC (monthly capacity charge) equals monthly capacity payments incurred in previous months, which have not yet been invoiced in instances where the MCC is a credit to the Designated FCM Participant or have not yet been invoiced and paid in instances where the MCC is a charge to the Designated FCM Participant. The MCC is estimated from the first day of the current delivery month until it is replaced by the actual settled MCC value when settlement is complete.

IMC (intra-month collateral) equals estimated monthly capacity payments incurred during the current delivery month as limited by the difference (which shall in no event be less than zero) between (A) the minimum of the applicable monthly stop-loss and the remaining annual stop-loss as described in Section III.13.7.3.1 and Section III.13.7.3.2 of Market Rule 1, respectively, and (B) the amount of additional FCM Delivery Financial Assurance when considering the Designated FCM Participant's current month FCM Delivery Financial Assurance obligation as compared to the Designated FCM Participant's next month FCM Delivery Financial Assurance obligation, in each case without giving effect to the IMC and MCC variables when calculating such additional amount. Where the estimated monthly capacity payments for each Designated FCM Participant, shall be updated three (3) days after publication of the most recent FCM Preliminary Capacity Performance Score report (or equivalent report) on the Market Information Server.

DFAMW (delivery financial assurance MW) equals the sum of the Capacity Supply Obligations of each resource in the Designated FCM Participant's portfolio for the month, excluding the Capacity Supply Obligation of any resource that has reached the annual stop-loss as described in Section III.13.7.3.2 of Market Rule 1. If the calculated DFAMW is less than zero, then the DFAMW will be set equal to zero.

PE (potential exposure) is a monthly value calculated for the Designated FCM Participant's portfolio as the difference between the Capacity Supply Obligation weighted average Forward Capacity Auction Starting Price and the Capacity Supply Obligation weighted average capacity price for the portfolio, excluding the Capacity Supply Obligation of any resource that has reached the annual stop-loss as described in Section III.13.7.3.2 of Market Rule 1. The Forward Capacity Auction Starting Price shall correspond to that used in the Forward Capacity Auction corresponding to the current Capacity Commitment Period and the capacity prices shall correspond to those used in the calculation of the Capacity Base Payment for each Capacity Supply Obligation in the delivery month.

In the case of a resource subject to a multi-year Capacity Commitment Period election made in a Forward Capacity Auction prior to the ninth Forward Capacity Auction as described in Sections III.13.1.1.2.2.4 and III.13.1.4.1.1.2.7 of Market Rule 1, the Forward

Capacity Auction Starting Price shall be replaced with the applicable Capacity Clearing Price (indexed for inflation) in the above calculation until the multi-year election period expires.

ABR (average balancing ratio) is the duration-weighted average of all of the system-wide Capacity Balancing Ratios calculated for each system-wide Capacity Scarcity Condition occurring in the relevant group of months in the three Capacity Commitment Periods immediately preceding the current Capacity Commitment Period and those occurring in the months within the relevant group that are prior to the current month of the current Capacity Commitment Period, as the data becomes available. [For the purpose of calculating the ABR, all Capacity Balancing Ratios, including Capacity Balancing Ratios for Capacity Scarcity Conditions that occurred in past Capacity Commitment Periods or in the months within the relevant group that are prior to the current month of the current Capacity Commitment Period, shall be calculated utilizing the Capacity Balancing Ratio formula that is currently effective, as described in Section III.13.7.2.3 or Section III.15.8.2.3 of Market Rule 1.](#) Three separate groups of months shall be used for this purpose: June through September, December through February, and all other months. Until data exists to calculate this number, the temporary ABR for June through September shall equal 0.90; the temporary ABR for December through February shall equal 0.70; and the temporary ABR for all other months shall equal 0.60.

CWAP (capacity weighted average performance) is the capacity weighted average performance of the Designated FCM Participant's portfolio. For each resource in the Designated FCM Participant's portfolio, excluding any resource that has reached the annual stop-loss as described in Section III.13.7.3.2 of Market Rule 1, and excluding from the remaining resources the resource having the largest Capacity Supply Obligation in the month, the resource's Capacity Supply Obligation shall be multiplied by the average performance of the resource. The CWAP shall be the sum of all such values, divided by the Designated FCM Participant's DFAMW. If the DFAMW is zero, then the CWAP is set equal to one.

The average performance of a resource is the Actual Capacity Provided during Capacity Scarcity Conditions divided by the product of the resource's Capacity Supply Obligation and the equivalent hours of Capacity Scarcity Conditions in the relevant group of months

in the three Capacity Commitment Periods immediately preceding the current Capacity Commitment Period and those occurring in the months within the relevant group that are prior to the current month of the current Capacity Commitment Period, as the data becomes available. Three separate groups of months shall be used for this purpose: June through September, December through February, and all other months. Until data exists to calculate this number, the temporary average performance for gas-fired steam generating resources, combined-cycle combustion turbines and simple-cycle combustion turbines shall equal 0.90; the temporary average performance for coal-fired steam generating resources shall equal 0.85; the temporary average performance for oil-fired steam generating resources shall equal 0.65; the temporary average performance for all other resources shall equal 1.00. The applicable temporary average performance value will be used for new and existing resources until actual performance data is available.

SF (scaling factor) is a month-specific multiplier, as follows:

June and December	2.000;
July and January	1.732;
August and February	1.414;
All other months	1.000.

Peak Monthly Stop-loss equals the largest monthly stop-loss for the Designated FCM Participant that would occur during the period from the current delivery month through the following five consecutive months, where each monthly stop-loss is equal to the sum of the monthly stop-losses of each resource in the Designated FCM Participant's portfolio as described in Section III.13.7.3.1 of Market Rule 1.

Second Largest Monthly Stop-loss equals the second largest monthly stop-loss for the Designated FCM Participant that would occur during the period from the current delivery month through the following five consecutive months, where each monthly stop-loss is equal to the sum of the monthly stop-losses of each resource in the Designated FCM Participant's portfolio as described in Section III.13.7.3.1 of Market Rule 1.

2. Corporate Liquidity Assessment Methodology

The ISO will perform a "Corporate Liquidity Assessment" to determine the appropriate liquidity risk assessment category for each Designated FCM Participant (i.e., low risk,

3. Return of Non-Commercial Capacity Financial Assurance

Non-Commercial Capacity cleared in a Forward Capacity Auction up to and including the eighth Forward Capacity Auction that is declared commercial and has had its capacity rating verified by the ISO or otherwise becomes a Resource meeting the definition of Commercial Capacity, or that is declared commercial and had a part of its capacity rating verified by the ISO and the applicable Designated FCM Participant indicates no additional portions of that Resource will become commercial, that portion of the Resource shall no longer be considered Non-Commercial Capacity under the ISO New England Financial Assurance Policy and will instead become subject to the provisions of the ISO New England Financial Assurance Policy relating to Commercial Capacity; provided that in either such case, the Designated FCM Participant will need to include in the calculation of its Financial Assurance Requirement an amount attributable to any remaining Non-Commercial Capacity.

Once Non-Commercial Capacity associated with a Capacity Supply Obligation awarded in the ninth Forward Capacity Auction and all Forward Capacity Auctions thereafter becomes commercial, the Non-Commercial Capacity Financial Assurance Amount for any remaining Non-Commercial Capacity shall be recalculated according to the process outlined above for Non-Commercial Capacity participating in the ninth Forward Capacity Auction and all Forward Capacity Auctions thereafter.

4. Credit Test Percentage Consequences for Provisional Members

If a Provisional Member is required to provide additional financial assurance under the ISO New England Financial Assurance Policy solely in connection with (A) a supply offer of Non-Commercial Capacity into any Forward Capacity Auction and (B) its obligation to pay Participant Expenses as a Provisional Member, and that Provisional Member is maintaining the amount of additional financial assurance required under the ISO New England Financial Assurance Policy, then the provisions of Section III.B of the ISO New England Financial Assurance Policy relating to the consequences of that Market Participant's Market Credit Test Percentage equaling 80 percent (80%) or 90 percent (90%) shall not apply to that Provisional Member.

C. ~~[Reserved for Future Use]~~ SBE Financial Assurance

A Designated FCM Participant with System-Backed Export transactions, as defined in Section III.13.7.2.A and Section III.15.8.2.A of Market Rule 1, must include SBE Financial Assurance in the calculation of its FCM Financial Assurance Requirements under the ISO New England Financial Assurance Policy.

SBE Financial Assurance is calculated according to the following formula for a Designated FCM Participant with System-Backed Export transactions.

$$\text{SBE Financial Assurance} = (\text{PPR} * \text{SBE MW} * \text{Scarcity Hours}) - \text{MEC} - \text{PMEC}$$

Where:

PPR is the Performance Payment Rate as defined in Section III.13.7.2.5 and Section III.15.8.2.5 of Market Rule 1.

SBE MW equals the Designated FCM Participant's average MW of System-Backed Exports across all Capacity Scarcity Conditions in the relevant group of months in the three Capacity Commitment Periods immediately preceding the current Capacity Commitment Period and those occurring in the months within the relevant group that are prior to the current month of the current Capacity Commitment Period, as the data becomes available; provided, however, that, beginning on October 1, 2026, data from Capacity Scarcity Conditions that occurred prior to October 1, 2026 shall no longer be used once data is available from a Capacity Scarcity Condition in the relevant group of months in a prior Capacity Commitment Period or a Capacity Scarcity Condition in the months within the relevant group that are prior to the current month of the current Capacity Commitment Period. Three separate groups of months shall be used for this purpose: June through September, December through February, and all other months.

Scarcity Hours equals the highest total number of hours in which a Capacity Scarcity Condition occurred during any month within the relevant group of months in the three Capacity Commitment Periods immediately preceding the current Capacity Commitment Period and those occurring in the months within the relevant group that are prior to the current month of the current Capacity Commitment Period, as the data becomes available. Three separate groups of months shall be used for this purpose: June through September, December through February, and all other months.

MEC (monthly export charges) equals System-Backed Export charges incurred in previous months, which have not yet been invoiced in instances where the MEC is a credit to the Designated FCM Participant or have not yet been invoiced and paid in instances where the MEC is a charge to the Designated FCM Participant. The MEC is estimated from the first day of the current month until it is replaced by the actual settled MEC value when settlement is complete.

PMEC (preliminary export charges) equals estimated System-Backed Export charges incurred in the current month. Where the estimated System-Backed Export charges shall be updated three (3) days after publication of the applicable report on the Market Information Server.

D. Loss of Capacity and Forfeiture of Non-Commercial Capacity Financial Assurance

If a Designated FCM Participant that has acquired Capacity Supply Obligations associated with Non-Commercial Capacity is in default under the ISO New England Financial Assurance Policy or the ISO New England Billing Policy and does not cure such default within the appropriate cure period, or if a Designated FCM Participant is in default under the ISO New England Financial Assurance Policy or the ISO New England Billing Policy during the period between the day that is three Business Days before the FCM Deposit is required and the first day of the Forward Capacity Auction and does not cure such default within the appropriate cure period, then: (i) beginning with the first Business Day following the end of such cure period that Designated FCM Participant will be assessed a default charge of one percent (1%) of its total Non-Commercial Capacity Financial Assurance Amount at that time for each Business Day that elapses until it cures its default; and (ii) if such default is not cured by 5:00 p.m. (Eastern Time) on the sooner of (x) the fifth Business Day following the end of such cure period or (y) the second Business Day prior to the start of the next scheduled Forward Capacity Auction or annual reconfiguration auction or annual Capacity Supply Obligation Bilateral submission (such period being referred to herein as the “Non-Commercial Capacity Cure Period”), then, in addition to the other actions described in this Section VII, (A) all Capacity Supply Obligations associated with Non-Commercial Capacity that were awarded to the defaulting Designated FCM Participant in previous Forward Capacity Auctions and reconfiguration auctions and that the defaulting Designated FCM Participant acquired by

EXHIBIT ID
ISO NEW ENGLAND BILLING POLICY

Table of Contents

SECTION 1 – OVERVIEW

SECTION 2 – TIMING AND CONTENT OF STATEMENTS

SECTION 3 – PAYMENT PROCEDURES

SECTION 4 – LATE PAYMENT CHARGES; LATE PAYMENT ACCOUNTS

SECTION 5 – SHORTFALL FUNDING ARRANGEMENT; PAYMENT DEFAULT SHORTFALL
FUND

SECTION 6 – BILLING DISPUTE PROCEDURES

SECTION 7 – WEEKLY BILLING PRINCIPLES FOR NON-HOURLY CHARGES

EXHIBIT ID ISO NEW ENGLAND BILLING POLICY

SECTION 1 – OVERVIEW

Section 1.1 – Scope. The objective of this ISO New England Billing Policy is to define the billing and payment procedures to be utilized in administering charges and payments due under the Transmission, Markets and Services Tariff and the ISO Participants Agreement, in each case as amended, modified, supplemented and restated from time to time (collectively, the “Governing Documents”). Capitalized terms used but not defined in the ISO New England Billing Policy shall have the meanings specified in Section I. The ISO New England Billing Policy applies to the ISO, the Market Participants, Non-Market Participant Transmission Customers, PTOs, and Market Participants that transact only in the FTR Auction (“FTR-Only Customers”) (referred to herein collectively as the “Covered Entities” and individually as a “Covered Entity”) for billing and payments procedures for amounts due under the Governing Documents, including without limitation those procedures related to the New England Markets. As reflected and specified in Section 3 hereof, the ISO’s obligation to make Payments (as defined below) is contingent on its receipt of sufficient aggregate Charges (as defined below) (or in cases of defaults in Covered Entities’ payments of Charges, on the ISO’s drawdowns under the ISO New England Financial Assurance Policy or recovery using the mechanisms specified in Section 3, 4 and 5 hereof).

Section 1.2 – Financial Transaction Conventions. The following conventions have been adopted in defining sums of money to be paid or received under the ISO New England Billing Policy:

- a) The term “Charge” refers to a sum of money due from a Covered Entity to the ISO, either in its individual capacity or as billing and collection agent for NEPOOL pursuant to the Participants Agreement.
- b) The term “Payment” refers to a sum of money due to a Covered Entity from the ISO. Amounts due to and from the ISO include amounts collected and paid by the ISO as billing and collection agent for NEPOOL pursuant to the Participants Agreement.

some Statements may have fewer days of settled data for certain Hourly Charges if fewer days have been settled for those Hourly Charges on the morning of the day that such Statements are issued; a following Statement may have more days of settled data for those Hourly Charges when it becomes possible to catch up on the settled data. Statements will include contiguous month-to-month hourly market billing data and will have separate line items for any hourly market data that may cross calendar months. For example, if a Statement's billing period includes May 30 through June 2, and all of those days are fully settled, the June 8 Statement would have one line item for the period May 30 to May 31 and one line item for the period June 1 to June 2. The Job Aid on the ISO web site will be updated weekly for any information necessary to be distributed through that medium.

Section 2.2 – Monthly Statements for Non-Hourly Charges. The first Statement issued on a Monday after the ninth of a calendar month will include both the Hourly Charges for the relevant billing period and Non-Hourly Charges for the immediately preceding calendar month (hereinafter sometimes referred to as a “Monthly Statement”). Resettlements determined in accordance with the procedures set forth in Market Rule 1 will be included in the monthly Statement for Non-Hourly Charges.

Section 2.3 – Statements for Weekly Billing Non-Hourly Charges. The ISO shall implement any weekly billing arrangements for Non-Hourly Charges effected under the ISO New England Financial Assurance Policy in accordance therewith and with the procedures set forth in Section 7 below.

Section 2.4 – Contents of Statements. Each Statement for Hourly and Non-Hourly Charges will include all of the following line items that are applicable to the Covered Entity receiving such Statement for the period to which such Statement relates:

- a) *Invoice or Remittance Advice Amount*. The net amount of all Charges and Payments owed by or due to a Covered Entity for the relevant Statement. The ISO shall issue an Invoice where the Covered Entity owes monies. The ISO shall issue a Remittance Advice where the Covered Entity is owed monies.

- b) *OATT Charges and Payments.* The Charges owed by and the Payments owed to the Covered Entity under the OATT *other than* Transmission Charges, which are billed separately under Section 2.5 below.
- c) *ISO Self-Funding Charges.* The Charges owed by the Covered Entity under Section IV of the Transmission, Markets and Services Tariff, categorized by the section or schedule under which such Charges arise.
- d) *Markets Charges and Payments.* The Hourly Charges owed by and the Payments for Hourly Charges owed to the Covered Entity as a result of transactions in each of the New England Markets administered by the ISO under Section III of the Transmission, Markets and Services Tariff.
- e) *Monthly Forward Capacity Market Charges and Payments.* The Non-Hourly Charges owed by and the Payments for Non-Hourly Charges owed to the Covered Entity as a result of Capacity Performance Payments, [System-Backed Export Charges](#), and other transactions in the Forward Capacity Market.
- f) *Participant Expenses.* As defined in the Participants Agreement, the Covered Entity's share of costs and expenses that are incurred pursuant to authorization of the Participants Committee and are not considered costs and expenses of ISO.
- g) [Reserved for Future Use]
- h) *Other Amounts due under the Participants Agreement.* The Charges owed by or the Payments owed to the Covered Entity under the Participants Agreement to the extent that those amounts are not included in items (b)-(g) above.
- i) *Other Non-Hourly Charges, Payments or Adjustments.* Any other Non-Hourly Charges, Payments for Non-Hourly Charges, or adjustments owed by or to the Covered Entity that are not included in items (b)-(h) above. These items may be due to retroactive billing adjustments, late payment fees, penalties or other items collectible under the Governing Documents.

- j) *Billing Periods.* The billing period (from and to dates) covered for each line item on the Statement. The billing periods for the various line items are not necessarily the same because of differences in timing of settlements and because of retroactive adjustments.
- k) *Payment Due Date and Time.* If the Statement is an Invoice, the date and time on which the net amount due is to be received by the ISO.
- l) *Wire Transfer Instructions.* Details including the account number, bank name, routing number and electronic transfer instructions which, in the case of an Invoice, will be for the ISO account to which ISO Charges owed by the Covered Entity are to be paid or, in the case of a Remittance Advice, will be for the Covered Entity's account to which the ISO shall remit Payments for ISO Charges owed to that Covered Entity (as previously provided to the ISO by such Covered Entity).

Section 2.5 – Monthly Statements for Transmission Charges. On the same date when each Monthly Statement is issued, the ISO shall provide electronically to each Covered Entity owing or owed any Transmission Charges for the preceding month a Statement (which may be combined with that Monthly Statement) showing all of the Transmission Charges for that Covered Entity for that preceding month (hereinafter sometimes referred to as a “Transmission Statement”). Any resettlements of Transmission Charges will also be included on the Transmission Statement. Each Transmission Statement will also include: (i) the billing month covered by the Transmission Statement; (ii) if the Transmission Statement is an Invoice, the date and time on which the net amount due is to be received by the ISO; and (iii) details including the account number, bank name, routing number and electronic transfer instructions which, in the case of an Invoice, will be for the ISO account to which Transmission Charges owed by the Covered Entity are to be paid or, in the case of a Remittance Advice, will be for the Covered Entity's account to which the ISO shall remit Payments for Transmission Charges owed to that Covered Entity (as previously provided to the ISO by such Covered Entity).

Section 2.6 – Certain Subsequent Adjustments to Previously Issued Statements.



memo

To: NEPOOL Markets Committee

From: Enrico De Magistris, Economist

Date: May 6, 2026

Subject: Pay-for-Performance Revisions: Treatment of External Transactions (WMPP ID: 190)

The ISO is requesting a vote on proposed Tariff revisions to update the Pay-for-Performance treatment of external transactions.

By way of background, system-backed exports are currently not charged the Performance Payment Rate (PPR) during a Capacity Scarcity Condition (CSC). Stakeholders, the External Market Monitor, and the Internal Market Monitor have noted the possible inefficiencies caused by omitting exports from performance exposure during periods of system stress and highlighted a potential inefficiency where market participants could receive Pay-for-Performance credits without contributing to system reliability. As a result, the ISO proposes charging system-backed exports the PPR during CSC.

This proposal improves market efficiency by ensuring that the region does not bear the cost that net exporters impose on the region during a CSC. Further, to align the treatment of exports in the Capacity Balancing Ratio, the ISO proposes subtracting system-backed exports from the numerator of the balancing ratio, aligning with the treatment of generator-backed exports.

The Markets Committee has reviewed the proposed changes highlighted above including the Market Rule 1 language and corresponding I.2.2 definitions. The proposal has been presented on the meeting dates outlined below:

- March 10-12, 2026, [agenda item #05](#)
- April 14-16, 2026, [agenda item #04](#)
- May 12-14, 2026, [agenda item #03](#)



Pay-for-Performance Revisions: Treatment of External Transactions

Proposed Revisions to PFP Treatment of External Transactions

Enrico De Magistris & Megan Sweitzer

ECONOMIST & LEAD ANALYST

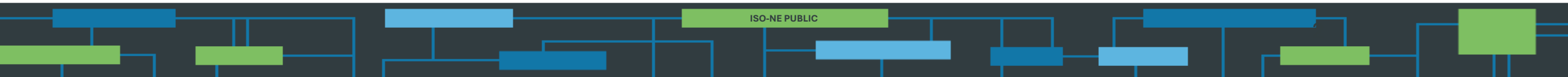


Pay for Performance Revisions: Treatment of External Transactions

NEPOOL PARTICIPANTS COMMITTEE
JUNE 16-18, 2026 SUMMER MEETING, AGENDA ITEM #7
Attachment E
WPFP ID:
190

Proposed Effective Date: October 1, 2026

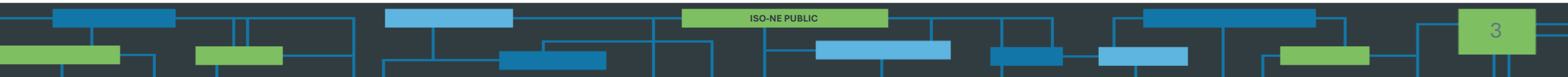
- The External Market Monitor (EMM) and the Internal Market Monitor (IMM) have highlighted a possible improvement to the efficiency of the Forward Capacity Market in its treatment of external transactions. Stakeholders have also expressed interest in this topic
- ISO-NE proposes changes to the Pay-for-Performance (PFP) treatment of external transactions to improve market efficiency
- Today's discussion focuses on the review of this area for improvement and introduces the proposed change
 - During a Capacity Scarcity Condition (CSC), ISO-NE proposes to charge at the Performance Payment Rate (PPR) for exports that are backed by ISO-NE's system, but not by a specific generator
- In addition, today's discussion provides ISO-NE's initial thinking regarding the potential removal of system-backed exports from the numerator of the Balancing Ratio (BR) during a CSC



Background

Exports are a component of PFP Settlements

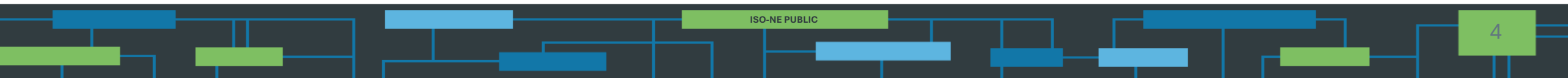
- There are two types of External Transaction Sales (Exports) that are relevant to this project
 1. Exports that are associated with the energy and reserves that a generator provides to the ISO-NE system, submitted in accordance with III.1.10.7(f)
 2. Exports that are **not** associated with a specific generator in the ISO-NE system
 - For convenience, these exports will be referred as "system-backed exports"



Background (cont.)

Exports are a component of PFP Settlements

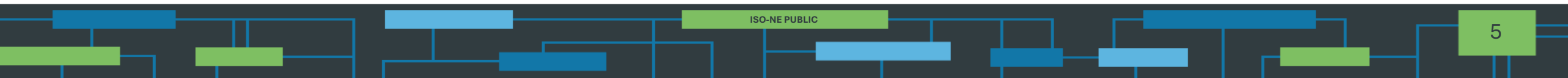
- Under current rules: Exports reduce the Actual Capacity Provided (ACP) of two kinds of resources, *but not below 0*
 - For generator capacity Resources associated with an export: $ACP = \text{Energy} + \text{Reserves} - \text{Exports}$
 - This reduction of ACP is provided in Ill.13.7.2.2(a), last sentence
 - If exports exceed a generator's energy and reserves, then those exports are effectively backed by the ISO-NE system but do not receive a PFP charge
 - For import capacity resources, ACP is proportional to Net Energy Delivered, *i.e.*, to Imports – Exports
 - If exports exceed imports, the excess exports do not receive a PFP charge
- As shown in the next slide, this floor at 0 creates a market inefficiency



Rationale for Change

In theory, two market participants could coordinate their external transactions scheduling to receive PFP credits without improving reliability

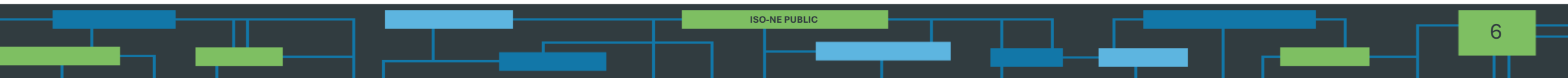
- There is an opportunity for increased efficiency by removing a method in which market participants could receive PFP credits without contributing to system reliability
- For example, during a CSC, assume:
 - Participant A has 0 CSO, schedules 0MWh of imports, 1MWh of exports, and *does not* receive PFP charges
 - Participant B has 0 CSO, schedules 1MWh of imports, 0MWh of exports, and *does* receive PFP credits
- These two transactions collectively result in no power flowing, but do not net in settlement because they are submitted by different market participants
 - The market participants could transact outside the ISO-NE system to share the PFP credits
 - To the best of the ISO's knowledge, no participant has engaged in this market inefficiency
- This market inefficiency affects resources that are charged to pay for this PFP credit



Proposed Solution

Charging system-backed exports the PPR during a CSC improves market efficiency

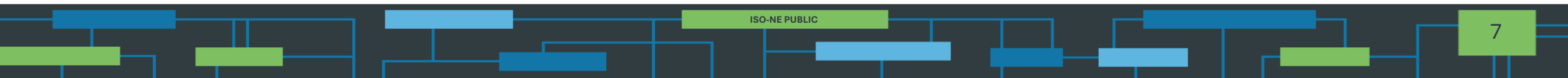
- To resolve the market inefficiency, the ISO proposes to *charge system-backed exports the PPR during a Capacity Scarcity Condition*
 - *System-backed exports*: Exports that are either 1) associated with a generator, but exceed the generator's energy and reserves provided, or 2) not associated with a generator
- Going back to the previous example, under this proposal
 - Participant A, who schedules a 1MWh *net* export, is charged 1MWh x PPR
 - Participant B, who schedules a 1MWh *net* import, is credited 1MWh x PPR
 - Collectively, the two transactions result in \$0 net revenue, which resolves the inefficiency



Proposed Solution (cont.)

The ISO is not proposing to charge generator-backed exports

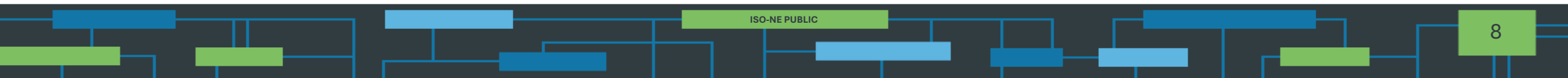
- Generator-backed exports reduce the generator's Actual Capacity Provided, and thus reduce the PFP credits or increase the PFP charges of that generator
- In this case, the combination of the generator and its associated exports is neither alleviating nor worsening the CSC
 - Note that if an export is associated with a generator, but exceeds the generator's energy and reserves, then the excess portion of that export is backed by the ISO-NE system, and will receive a PFP charge under this proposal
- The proposal achieves two goals:
 1. Eliminate the market inefficiency identified by the EMM and the IMM
 2. Ensure that resources do not bear the cost that net exporters impose on the ISO-NE system during a CSC



Proposed Solution – Detailed Design

Charge system-backed export the PPR during a CSC

- The ISO proposes to create a new PFP charge quantity: system-backed exports (SBE). Such quantity would be charged the Performance Payment Rate (PPR)
- SBE would be calculated as follows:
 - If a generator provides less energy and reserves to the ISO-NE system than its scheduled exports, then the exports in excess would be a system-backed export. In formulas,
 - $SBE_{\text{generator resource}} = \min (\text{Energy Quantity} + \text{Reserve Provided} - \text{Exports}_{\text{Gen}}, 0) \times \text{PPR}$
 - If a participant submits exports (not associated with a generator) in excess of imports, then the excess exports would be a system-backed export. In formulas,
 - $SBE_{\text{Participant}} = \min (\text{Imports} - \text{Exports}_{\text{Non Gen}}, 0) \times \text{PPR}$
- For example:
 - Generator A has 0 Capacity Supply Obligation (CSO). It schedules 10 MW of exports, provides 9MWh of energy and reserves → Generator A is charged 1 MWh x PPR
 - Participant B has 0 CSO in import capacity resources. It schedules 0 MW of imports and 1 MWh exports. → Participant B is charged 1 MWh x PPR



Proposed Solution – Detailed Design (cont.)

The ISO does not propose changes to calculation of stopped losses

- Under today's rules, a resource's capacity performance charges are limited through the stop-loss mechanism (III.13.7.3)
- The ISO does *not* propose changes to calculation of stopped losses
 - Specifically, SBE charges would not be included in the negative capacity payments that are limited by the monthly or annual capacity stop-loss mechanism
- Excluding SBE charges from the calculation of stopped losses achieves two objectives:
 - Ensures the proposed solution works as intended
 - Otherwise, a resource with 0 CSO, and therefore a stop loss limit of \$0, would effectively not be charged for exports during a CSC
 - “Beneficiary pays” principle: CSO resources are only responsible for the stopped losses of other CSO resources who have been charged for negative performance scores during a CSC

Proposed Solution – Detailed Design (cont.)

The ISO does not propose changes to ACP calculation, or External Transaction scheduling

- **ACP Calculation:**
 - The ISO does *not* propose to change how the Actual Capacity Provided of any resource is calculated
- **External Transaction scheduling:**
 - Under the proposed changes, exports may prefer to be curtailed during a CSC, rather than be charged the PPR
 - The ISO does *not* propose to change the scheduling process for exports
 - Next month, the ISO will present additional information on the existing process for curtailing exports during a CSC
 - Please submit specific questions to Jasleen Singh (jsingh@iso-ne.com) by March 23rd, 2026

Potential Additional Change

Currently, system-backed exports are included in load in the capacity Balancing Ratio

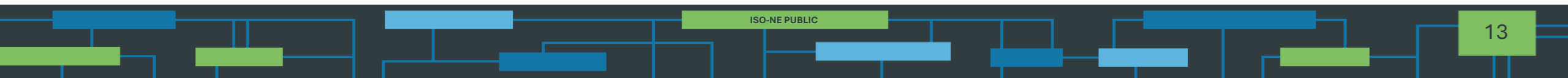
- The Capacity Balancing Ratio (BR) is defined as: $(\text{load} + \text{reserve requirements}) / (\text{Total Capacity Supply Obligation})$
 - Where load = Total Actual Capacity Provided – Designated Reserves
- Currently, system-backed exports are included in the Capacity Balancing Ratio as load
- The ISO's initial thinking is to remove a participant's system-backed exports from the BR
 - This change aligns with the treatment of generator-backed exports, which reduce the BR by lowering the generator's Actual Capacity Provided
 - This change results in a conceptually simpler settlement, because it reduces charges and reduces balancing fund credits

Conclusion

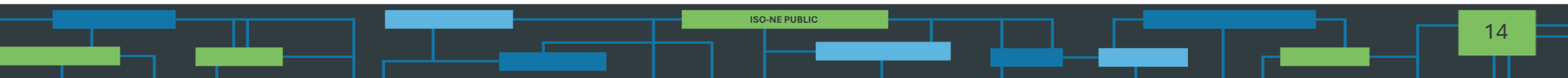
- The ISO proposes to charge system-backed exports the PPR to improve market efficiency
- The ISO may propose to subtract system-backed exports from the numerator of the Balancing Ratio
- In April, the ISO will discuss:
 - Follow-ups from today's meeting
 - The curtailment process for exports
 - Tariff redlines

Stakeholder Schedule

Stakeholder Committee and Date	Scheduled Project Milestone
Markets Committee March 10-12, 2026	Summary of opportunity for improvement-and proposed design
Markets Committee April 14-16, 2026	Additional details on design and initial review of proposed Tariff language and any stakeholder amendments
Markets Committee May 12-13, 2026	Additional review of proposed Tariff language, stakeholder amendments, and vote
Participants Committee June 16-18, 2026	Vote

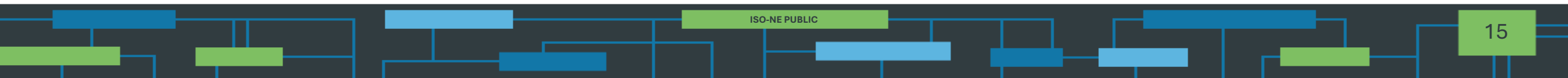


Questions



Acronyms Used in this Presentation

- EMM = External Market Monitor
- IMM = Internal Market Monitor
- PFP = Pay-for-Performance
- CSC = Capacity Scarcity Condition
- BR = Capacity Balancing Ratio
- ACP = Actual Capacity Provided
- SBE = System-backed Exports
- PPR = Performance Payment Rate
- CSO = Capacity Supply Obligation





Pay-for-Performance Revisions: Treatment of External Transactions

Proposed Revisions to PFP Treatment of External Transactions

Enrico De Magistris & Megan Sweitzer

ECONOMIST & LEAD ANALYST



Pay for Performance Revisions: Treatment of External Transactions

NEPOOL PARTICIPANTS COMMITTEE
JUNE 16-18, 2026 SUMMER MEETING, AGENDA ITEM #7
Attachment F
WPFP ID:
190

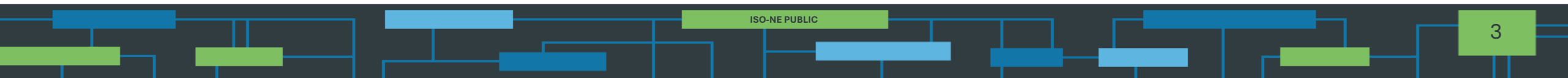
Proposed Effective Date: October 1, 2026

- The External Market Monitor (EMM) and the Internal Market Monitor (IMM) have highlighted a possible improvement to the efficiency of the Forward Capacity Market in its treatment of external transactions. Stakeholders have also expressed interest in this topic
- The ISO presented proposed changes to the Pay-for-Performance (PFP) treatment of external transactions to improve market efficiency at the March Markets Committee Meeting
- Today's discussion includes
 - Follow-up questions from March MC
 - ISO's proposal to remove System-Backed Exports (SBE) from the numerator of the balancing ratio (BR) during a Capacity Scarcity Condition (CSC)
 - Overview of the curtailment process for exports during a CSC
 - Initial review of proposed Tariff Language

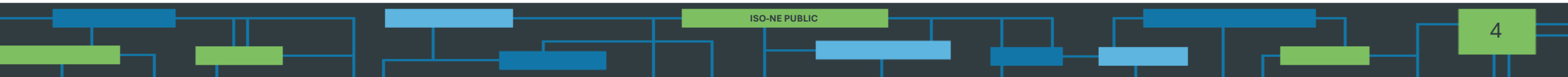
Overview of Proposed Solution

Charge system-backed exports the PPR during a CSC

- ISO-NE proposes to create a new PFP charge quantity, system-backed exports (SBE). Such quantity would be charged the Performance Payment Rate (PPR) and removed from the numerator of the Capacity Balancing Ratio (BR)
- SBE would be calculated as follows:
 - If a generator provides less energy and reserves to the ISO-NE system than its scheduled exports, then the exports in excess would be a system-backed export
 - **Formula:** $SBE_{\text{generator resource}} = \min (\text{Energy Quantity} + \text{Reserve Provided} - \text{Exports}_{\text{Gen}}, 0) \times \text{PPR}$
 - If a participant submits exports (not associated with a generator) in excess of imports, then the excess exports would be a system-backed export
 - **Formula:** $SBE_{\text{Participant}} = \min (\text{Imports} - \text{Exports}_{\text{Non Gen}}, 0) \times \text{PPR}$
- The ISO does *not* propose changes to the calculation of Actual Capacity Provided or the stop loss mechanism

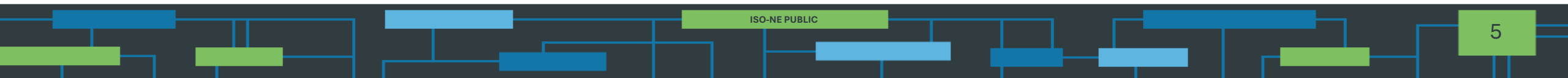


FOLLOW-UPS FROM MARCH MARKETS COMMITTEE



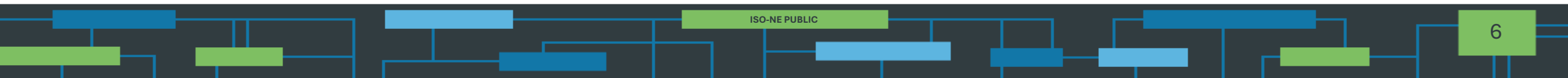
Follow-ups from March MC

- **Question:** Would external transactions scheduled for emergency assistance programs be subject to the new charge?
 - **Background**
 - External transactions scheduled for emergency assistance programs are not part of the external transactions specified under III.1.10.7 by Market Participants
 - Rather, emergency assistance programs are managed between the regions' control rooms
 - **Answer**
 - The ISO does not propose to charge exports scheduled for emergency assistance programs
- **Question:** Would imports backed by a generator in another control area still receive capacity performance credits if that generator were not running?
 - **Answer**
 - The ISO cannot verify whether a generator in another control area is running, unless the external transaction corresponding to this import is scheduled through the external nodes
 - Unless the corresponding import is curtailed by the other control area, the import receives performance credit



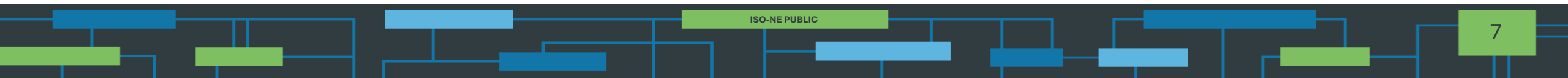
Follow-ups from March MC

- **Question:** How are flows maintained for capacity that is dedicated to another region?
 - **Background**
 - Generator resources in New England can sometimes acquire an obligation to provide capacity to another region
 - **Answer**
 - Energy exports associated with a generator that sold capacity to another region receive the new charge *only insofar as the exports exceed the generator's energy and reserves*
 - For example, if a generator with a capacity obligation in NYISO trips offline during a CSC, the scheduled exports associated with that generator would be subject to the proposed charge unless it is curtailed



PROPOSED CHANGE TO CAPACITY BALANCING RATIO

Additional details on the proposed removal of system-backed exports from Capacity Balancing Ratio



The ISO proposes to remove SBE from the numerator of the Capacity Balancing Ratio

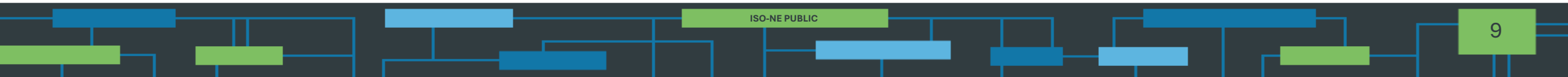
NEPOOL PARTICIPANTS COMMITTEE
JUNE 16-18, 2026 SUMMER MEETING, AGENDA ITEM #7
Attachment F

Currently, system-backed exports are included in load in the capacity Balancing Ratio

- The Capacity Balancing Ratio (BR) is defined as: $(\text{load} + \text{reserve requirement}) / (\text{Total Capacity Supply Obligation})$
 - Where load = Total Actual Capacity Provided – Designated Reserves
- Currently, system-backed exports are included in the Capacity Balancing Ratio
- ISO-NE proposes to remove system-backed exports from the numerator of the balancing ratio
 - This change aligns with the treatment of generator-backed exports, which reduce the BR by lowering the generator's Actual Capacity Provided
 - This change results in a conceptually simpler settlement, because it reduces charges and reduces balancing fund credits

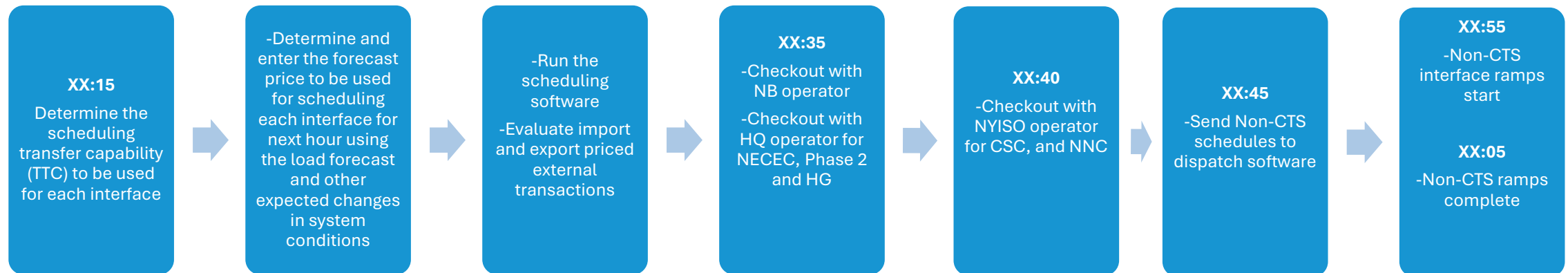
EXTERNAL TRANSACTIONS SCHEDULING PROCESS

Presented by Jonathan Gravelin (Senior Manager, Control Room Operations)



Non-CTS Scheduling Process

- Process performed on an hourly basis for the following interfaces:
 - Highgate (HG)
 - Phase II
 - New England Clean Energy Connect (NECEC)
 - New Brunswick
 - Norwalk – Northport Cable(NNC)
 - Cross Sound Cable (CSC)



* All times are approximate

CTS Scheduling Process

- Process performed every 15min for the NY AC Ties

XX:00, :15, :30, :45

- Check NYN Scheduling or Manage CTS Data displays for data quality
- Verify correct transfer capabilities (TTCs) are in use
- Check both NE and NY interchange values are matched and are binding

XX:02, :17, :32, :47

- Verbal checkout with NYISO operator
- Timing of verbal checkout is variable, but must occur after the prior interval ramp starts
- Send schedule to dispatch software
- The :00 CTS schedule is sent concurrently with the Non-CTS schedules

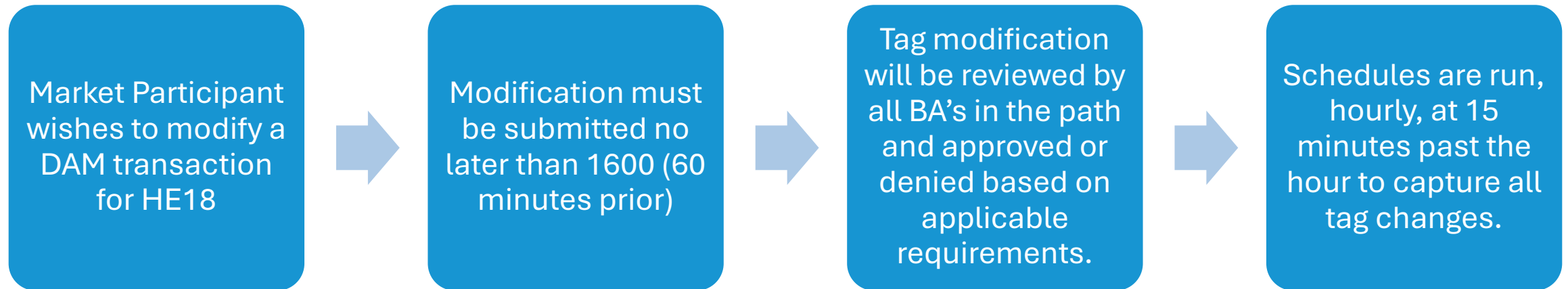
XX:10, XX:25, XX:40, XX:55

- CTS Schedules begin ramping

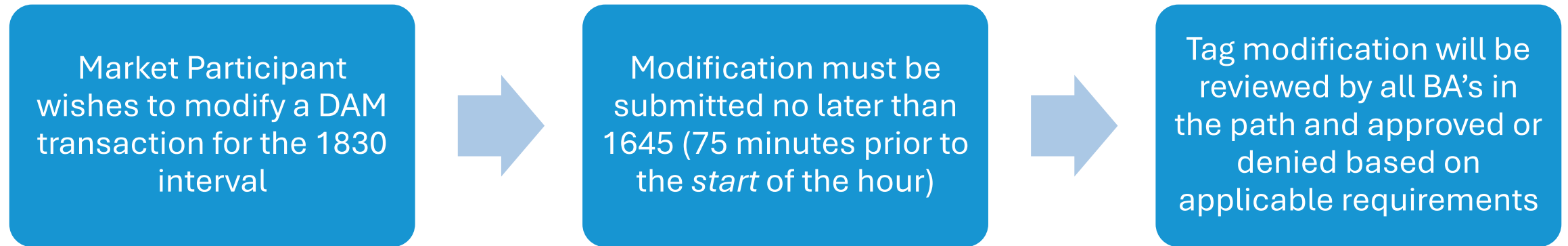
XX:05, XX:20, XX:35, XX:50
CTS schedule ramp complete

* All times are approximate

Non-CTS Transaction Modification



CTS Transaction Modification



Pre-OP4 Curtailment Process

Curtailed based on their Day Before Checkout value

If Day Before was an export, can curtail as low as zero. This would decrease exports

If Day Before was an import, sales would be curtailed as such to not exceed the Day before import value. This would increase imports

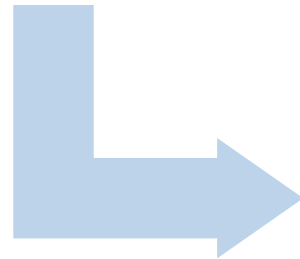
• CTS Interface

RT Only Exports will be curtailed to zero as needed

• Non-CTS

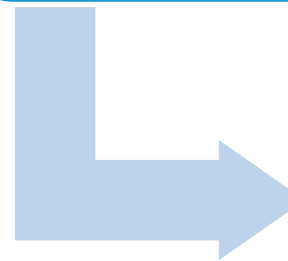
OP-4 Curtailments

Day Ahead Market tags do not get cut until OP-4 Action 5 has been implemented



Remaining exports cut to zero. This can result in an import greater than the Day Before value

- CTS Interface



DAM transactions cut as needed

- Non-CTS

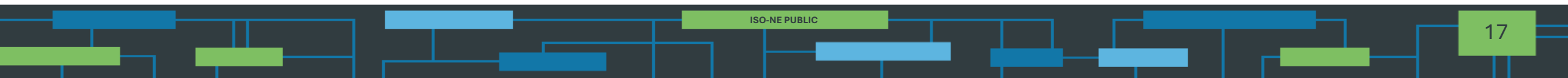
Can a participant adjust an external transaction that had been scheduled on the day-ahead market, within some lead time of the scheduled period?

- It is possible to modify existing transactions on both CTS (75 minutes prior to the start of the hour) and Non-CTS (60 minutes prior to the start of the hour) interfaces in Real-Time, but the participant must meet the time-requirements as dictated in the Tariff and the modifications must meet reliability considerations as required by INT-006-5. In short, BA's along the path of the tag must have time to evaluate and approve all tag modifications

Alternatively, can that participant schedule within some lead period, an external transaction of the opposite direction to annul what had been scheduled prior to that day?

- Yes, a participant can elect to submit a RT transaction in the opposite direction of their DAM transaction, but it will be subject to the same time and reliability considerations as a modification to the existing tag. Also, as with any market transaction, there is no guarantee that the two counter-flowing contracts will net-out how the participant would like

PROPOSED TARIFF CHANGES



Summary of Proposed Tariff Changes

- Section I.2.2 “Definitions”
 - Add definition of System-Backed Exports
- Section III.13.7.2.A and III.15.8.2.A “System-Backed Export Charges”
 - Define System-Backed Exports value and System-Backed Export Charge
- Section III.13.7.2.3 and III.15.8.2.3 “Capacity Balancing Ratio”
 - Remove System-Backed Exports from the Load Component of the Capacity Balancing Ratio
- Section III.13.7.4. and III.15.8.4 “Allocation of Deficient or Excess Capacity Performance Payments”
 - Add System-Backed Export Charges to deficient or excess Capacity Performance Payments for allocation

Summary of Proposed Tariff Changes

Section I.2.2 “Definitions”

Tariff Section	Tariff Change	Reason for Change
I.2.2	Insert “System-Backed Export is defined in Section III.13.7.2.A.1 and Section III.15.8.2.A.1 of Market Rule 1.”	Define System-Backed Exports
I.2.2	Insert “System-Backed Export Charge is calculated in accordance with Section III.13.7.2.A.2 and Section III.15.8.2.A.2 of Market Rule 1.”	Define System-Backed Exports

Summary of Proposed Tariff Changes

Section III.13.7.2.A.1, III.15.8.2.A.1 “System-Backed Export”

Tariff Section	Tariff Change	Reason for Change
III.13.7.2.A.1, III.15.8.2.A.1	“A System-Backed Export is an External Transaction submitted in accordance with Section III.1.10.7 or Section III.1.10.7.A to export internal energy out of the New England Control Area by a Market Participant in the Real-Time Energy Market: (1) that is not associated with a generator; or (2) for External Transactions associated with a generator, for which the megawatt amount of the External Transaction sale(s) associated with the generator is greater than the sum of the resource’s energy output plus the resource’s Reserve Quantity For Settlement. ”	Define System-Backed Exports for purpose of defining new charge quantity

Summary of Proposed Tariff Changes

Section III.13.7.2.A.2, III.15.8.2.A.2 “Calculation of System-Backed Export Charges”

Tariff Section	Tariff Change	Reason for Change
III.13.7.2.A.2, (III.15.8.2.A.2)	“For each five-minute interval in which a Capacity Scarcity Condition exists, the ISO shall calculate a System-Backed Export Charge: (1) for External Transactions associated with a generator, for each resource that submitted an External Transaction sale in the Real-Time Energy Market corresponding with the five-minute interval; and (2) for External Transactions not associated with a generator, for each Market Participant that submitted an External Transaction sale in the Real-Time Energy Market corresponding with the five-minute interval. For each five-minute interval, the System-Backed Export Charge shall be equal to the net System-Backed Export value, calculated in accordance with the formulas set forth below, multiplied by the Capacity Performance Payment Rate, as defined in Section III.13.7.2.5. ” (cont.) (“... as defined in III.15.8.2.5.”)	Define System-Backed Exports charge as the product of (System-Backed Export) and (Performance Payment Rate)

Summary of Proposed Tariff Changes (cont.)

Section III.13.7.2.A.2, III.15.8.2.A.2 “Calculation of System-Backed Export Charges”

Tariff Section	Tariff Change	Reason for Change
III.13.7.2.A.2, III.15.8.2.A.2	(Cont.) “For External Transactions associated with a generator, net System-Backed Export value = the lesser of (the energy output of the generator in the interval + the Reserve Quantity for Settlement of the generator in the interval – the hourly integrated delivered MW for the External Transaction sale(s) associated with the generator) or 0 System-Backed Export Charge = net System-Backed Export value × Capacity Performance Payment Rate ”	Define System-Backed Exports charge for generators as the product of (System-Backed Export) and (Performance Payment Rate)

Summary of Proposed Tariff Changes (cont.)

Section III.13.7.2.A.2, III.15.8.2.A.2 “Calculation of System-Backed Export Charges”

Tariff Section	Tariff Change	Reason for Change
III.13.7.2.A.2, III.15.8.2.A.2	(Cont.) “For External Transactions not associated with a generator, net System-Backed Export value = the lesser of (the hourly integrated delivered MW for the External Transaction purchase(s) of the Market Participant – the hourly integrated delivered MW for the External Transaction sale(s) of the Market Participant) or 0 System-Backed Export Charge = net System-Backed Export value × Capacity Performance Payment Rate Unless otherwise expressly stated, a System-Backed Export Charge shall not be treated as a Capacity Performance Payment under the Tariff.”	Define System-Backed Exports charge for market participants as the product of (System-Backed Export) and (Performance Payment Rate)

Summary of Proposed Tariff Changes

Section III.13.7.4., III.15.8.4. “Allocation of Deficient or Excess Capacity Performance Payments”

Tariff Section	Tariff Change	Reason for Change
III.13.7.4., III.15.8.4.	Insert “and System-Backed Export Charges.”	Add System-Backed Export Charges to Capacity Performance Payments in the balancing fund to allocate to resources after a CSC
III.13.7.4(a), III.15.8.4(a)	Insert “and System-Backed Export Charges.”	Add System-Backed Export Charges to Capacity Performance Payments in the balancing fund to allocate to resources after a system-wide CSC
III.13.7.4(b), III.15.8.4(b)	Insert “and System-Backed Export Charges.”	Add System-Backed Export Charges to Capacity Performance Payments in the balancing fund to allocate to resources after a zonal CSC

Summary of Proposed Tariff Changes

Section III.13.7.2.3 “Capacity Balancing Ratio”

Tariff Section	Tariff Change	Reason for Change
III.13.7.2.3(a)	Add “minus the sum of all absolute net System-Backed Export values calculated in accordance with the formulas set forth in Section III.13.7.2.A.2, in the New England Control Area during the interval.”	Remove System-Backed Exports from Capacity Balancing Ratio during a system-wide CSC resulting from a violation of the Minimum Total Reserve Requirement
III.13.7.2.3(b)	Add “minus the sum of all absolute net System-Backed Export values calculated in accordance with the formulas set forth in Section III.13.7.2.A.2, in the New England Control Area during the interval.”	Remove System-Backed Exports from Capacity Balancing Ratio during a system-wide CSC resulting from a violation of the Ten-Minute Reserve Requirement
III.13.7.2.3(b)	Add “minus the sum of all absolute net System-Backed Export values calculated in accordance with the formulas set forth in Section III.13.7.2.A.2, in the Capacity Zone during the interval.”	Remove System-Backed Exports from Capacity Balancing Ratio during a zonal CSC resulting from a violation of the Zonal Reserve Requirement

Summary of Proposed Tariff Changes

Section III.15.8.2.3 “Capacity Balancing Ratio”

Tariff Section	Tariff Change	Reason for Change
III.15.8.2.3(a)	Add “minus the sum of all absolute net System-Backed Export values calculated in accordance with the formulas set forth in Section III.15.8.2.A.2, in the New England Control Area during the interval.”	Remove System-Backed Exports from Capacity Balancing Ratio during a system-wide CSC resulting from a violation of the Minimum Total Reserve Requirement
III.15.8.2.3(b)	Add “minus the sum of all absolute net System-Backed Export values calculated in accordance with the formulas set forth in Section III.15.8.2.A.2, in the New England Control Area during the interval.”	Remove System-Backed Exports from Capacity Balancing Ratio during a system-wide CSC resulting from a violation of the Ten-Minute Reserve Requirement
III.15.8.2.3(b)	Add “minus the sum of all absolute net System-Backed Export values calculated in accordance with the formulas set forth in Section III.15.8.2.A.2, in the Capacity Zone during the interval.”	Remove System-Backed Exports from Capacity Balancing Ratio during a zonal CSC resulting from a violation of the Zonal Reserve Requirement

Conclusion

- ISO-NE proposes to charge system-backed exports the PPR to improve market efficiency by removing a method in which market participants could receive PFP credits without contributing to system reliability
- ISO-NE also proposes to remove the values of the corresponding system-backed exports from the numerator of the Balancing Ratio
- In May, we will discuss
 - Any follow-ups from today's meeting
 - Incremental Tariff redlines, if needed

Stakeholder Schedule

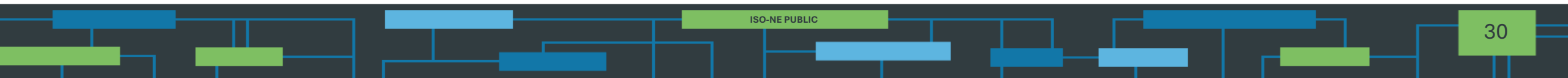
Stakeholder Committee and Date	Scheduled Project Milestone
Markets Committee March 10-12, 2026	<i>Summary of market inefficiency and proposed design</i>
Markets Committee April 14-15, 2026	Additional details on design and initial review of proposed Tariff language
Budget and Finance Subcommittee April 17, 2026	Introduce proposed Financial Assurance revisions
Budget and Finance Subcommittee May 8, 2026	Present associated Financial Assurance Policy redlines
Markets Committee May 12-13, 2026	Additional review of proposed Tariff language and Vote
Participants Committee June 16-18, 2026	Vote

Questions



Acronyms Used in this Presentation

- ACP = Actual Capacity Provided
- BR = Capacity Balancing Ratio
- CSC = Capacity Scarcity Condition
- CSO = Capacity Supply Obligation
- EMM = External Market Monitor
- IMM = Internal Market Monitor
- PFP = Pay-for-Performance
- PPR = Performance Payment Rate
- SBE = System-backed Exports





Pay-For-Performance Revisions: Financial Assurance Changes for External Transactions and Balancing Ratio Redlines

Financial Assurance redlines for revised treatment of External Transactions and Average Balancing Ratio revisions to conform with revisions made to cap the Capacity Balancing Ratio

Zach Shell

SUPERVISOR, MARKET AND CREDIT RISK

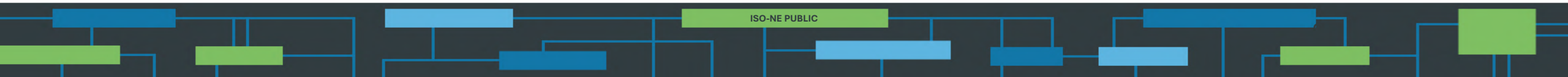


Pay-For-Performance: Financial Assurance Changes for External Transactions and Balancing Ratio

NEPOOL PARTICIPANTS COMMITTEE
JUNE 16-18, 2026 SUMMER MEETING, AGENDA ITEM #7
Attachment G
WMPP IDs:
189 & 190

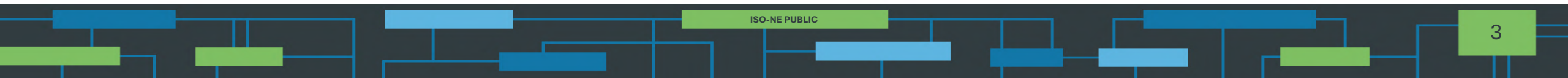
Proposed Effective Date: October 1, 2026

- During the April 17th BFS meeting, the ISO proposed updates to the Financial Assurance Policy (FAP) to conform with proposed changes to the treatment of External Transactions
 - A new Financial Assurance (FA) requirement was proposed to mitigate the risk of potential System-Backed Export (SBE) charges that may be incurred during future Capacity Scarcity Conditions (CSC)
- The ISO also discussed two proposals related to the FAP definition of Average Balancing Ratio (ABR)
 - All historical Balancing Ratios (BR) utilized within the ABR calculation will be replaced with a recalculated BR with SBE subtracted from the numerator of the BR calculation
 - Any BR used within the ABR calculation will have a maximum value of 1.0
- Today's discussion focuses on providing further details surrounding the implementation and impact of the proposals along with the redlines to the FAP



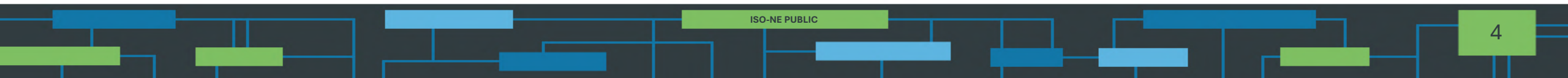
EXTERNAL TRANSACTIONS

FAP Revisions



Background

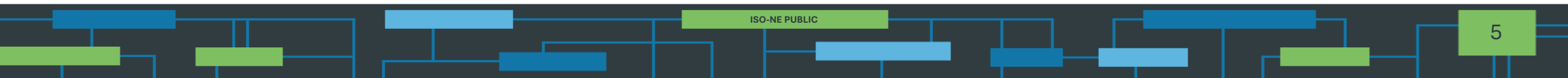
- During the April 17th BFS meeting, the ISO proposed updating the FAP to include a new financial assurance requirement
- **SBE FA = PPR * SBE MW * Scarcity Hours**
 - PPR = Performance Payment Rate
 - SBE MW = The Market Participant's Average SBE MWs across all CSCs occurring within the relevant group of months (summer, winter, shoulder) over the last 3 CCPs along with months within the relevant group prior to the current month during the current CCP
 - Scarcity Hours = The average amount of monthly CSC hours across all CSCs occurring within the relevant group of months (summer, winter, shoulder) over the last 3 CCPs along with months within the relevant group prior to the current month during the current CCP



Proposal - Updated

- **SBE FA = (PPR * SBE MW * Scarcity Hours) – MEC⁽¹⁾ – PMEC⁽¹⁾**
- PPR = Performance Payment Rate
- SBE MW = the Designated FCM Participant's average MW of System-Backed Exports across all Capacity Scarcity Conditions in the relevant group of months in the three Capacity Commitment Periods immediately preceding the current Capacity Commitment Period and those occurring in the months within the relevant group that are prior to the current month of the current Capacity Commitment Period, as the data becomes available; **provided, however, that, beginning on October 1, 2026, data from Capacity Scarcity Conditions that occurred prior to October 1, 2026 shall no longer be used once data is available from a Capacity Scarcity Condition in the relevant group of months in a prior Capacity Commitment Period or a Capacity Scarcity Condition in the months within the relevant group that are prior to the current month of the current Capacity Commitment Period.**
- Scarcity Hours = the **highest** total number of hours in which a Capacity Scarcity Condition occurred during any month within the relevant group of months in the three Capacity Commitment Periods immediately preceding the current Capacity Commitment Period and those occurring in the months within the relevant group that are prior to the current month of the current Capacity Commitment Period, as the data becomes available.
- **MEC (Monthly Export Charges) = System-Backed Export charges incurred in previous months, which have not yet been invoiced in instances where the MEC is a credit to the Designated FCM Participant or have not yet been invoiced and paid in instances where the MEC is a charge to the Designated FCM Participant. The MEC is estimated from the first day of the current month until it is replaced by the actual settled MEC value when settlement is complete.**
- **PMEC (Preliminary Monthly Export Charges) = estimated System-Backed Export charges incurred in the current month. Where the estimated System-Backed Export charges shall be updated three (3) days after publication of the applicable report on the Market Information Server.**

(1) MEC and PMEC are subtracted because incurred charges are negative numbers, therefore subtracted them within the formula will increase SBE FA

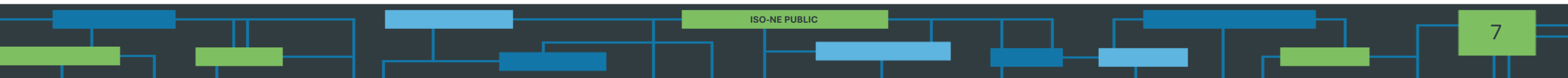


Example: SBE FA Calculation

- **SBE FA = (PPR * SBE MW * Scarcity Hours) – MEC – PMEC**
- Scenario
 - There are 2 months with CSCs within the lookback period for the relevant season
 - Neither the current month nor the prior month had CSCs; therefore, **MEC and PMEC are both zero**
 - The first month had a total of 2 scarcity hours (24 CSC intervals) where the MP exported an average of 100 MW
 - The second month had 1 scarcity hour (12 CSC intervals) where the MP exported an average of 40 MW
 - The PPR is \$3,500/ MWh
- The SBE MW used in the SBE FA calculation is a weighted average of SBEs during all scarcity hours. It is calculated by weighting each month's average SBEs by the number of scarcity hours and dividing by the total scarcity hours
 - **$((100 \text{ MW} * 2 \text{ hours}) + (40 \text{ MW} * 1 \text{ scarcity hour})) / 3 \text{ hours} = 80 \text{ MW}$**
- The Scarcity Hours used in the SBE FA calculation are 2, because that was the highest number of scarcity hours in any single month during which CSCs occurred
- Using a PPR of \$3,500, an SBE MW of 80, and 2 Scarcity Hours, the resulting SBE FA amount is
 - **$\$3,500 \text{ PPR} * 80 \text{ SBE MW} * 2 \text{ Scarcity Hours} = \$560,000$**

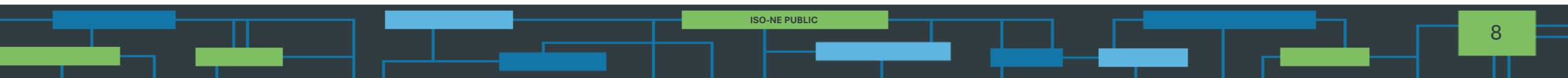
Impact of Proposal

- The proposed change to update the FAP to include the SBE FA requirement will result in total additional FA requirements for the market of ~\$1.6MM on average over the course of the first year it becomes effective (based on existing data, without respect for how future CSC events may alter FA requirements)
- The proposal only impacts the FA requirements for MPs that have historically had SBE transactions during CSCs within the last 3 years. MPs that have not had SBE transactions during any CSCs within the last 3 years will have no impact to their FA requirements
 - Likewise, MPs that showcase no SBE activity during future CSCs will have no additional FA requirements at that time



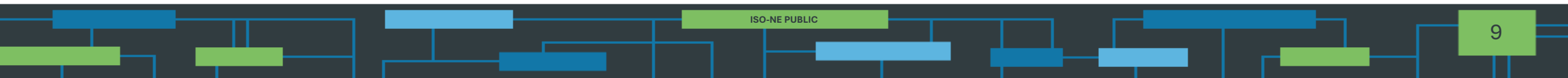
BALANCING RATIO

FAP Revisions



Background

- At the April 17th BFS, the ISO proposed an update to the FAP definition of Average Balancing Ratio (ABR) to reflect a cap of all historical BRs utilized within the ABR calculation at 1.0 to comply with FERC's order
- The ISO also proposed an update to the FAP definition of ABR to reflect that any BR used within the ABR calculation be replaced with a recalculated BR with SBEs subtracted from the numerator to conform with the proposed change to the BR formula

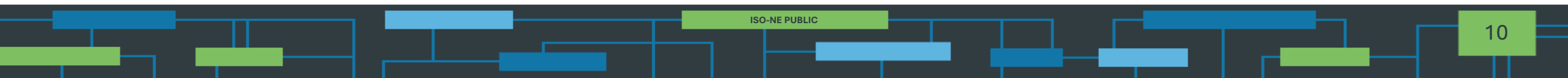


Example: ABR Calculation

- The below data represents how the BRs from each CSC event within the lookback period will be recalculated for purposes of utilization within the ABR calculation

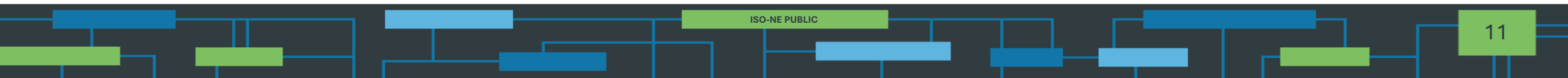
CSC Event Date	Season	Number of CSC Intervals	Original BR	Recalculated BR (SBE's removed and cap of 1.0)
Jun 2024	Summer	6 (0.5 hours)	0.869	0.847
Aug 2024	Summer	22 (1.833 hours)	0.903	0.883
Jun 2025	Summer	37 (3.083 hours)	1.031	0.999
Nov 2025	Shoulder	6 (0.5 hours)	0.696	0.634

- The ABR for each season during the first 12 months upon which the proposal is effective (assuming no additional CSC events occur) will therefore be:
 - Summer ABR = $((0.847 * 6) + (0.883 * 22) + (0.999 * 37)) / 65 = \mathbf{0.946}$
 - Winter ABR = **0.7** (default value as defined in the FAP in the absence of a CSC within the lookback period)
 - Shoulder ABR = $(0.634 * 6) / 6 = \mathbf{0.634}$



FINANCIAL ASSURANCE POLICY REDLINES

FAP Revisions



FAP Redlines: SBE FA

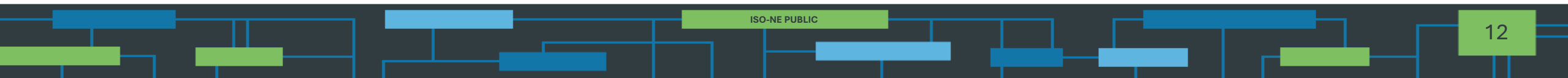
A Designated FCM Participant with System-Backed Export transactions, as defined in Section III.13.7.2.A and Section III.15.8.2.A of Market Rule 1, must include SBE Financial Assurance in the calculation of its FCM Financial Assurance Requirements under the ISO New England Financial Assurance Policy.

SBE Financial Assurance is calculated according to the following formula for a Designated FCM Participant with System-Backed Export transactions.

$$\text{SBE Financial Assurance} = (\text{PPR} * \text{SBE MW} * \text{Scarcity Hours}) - \text{MEC} - \text{PMEC}$$

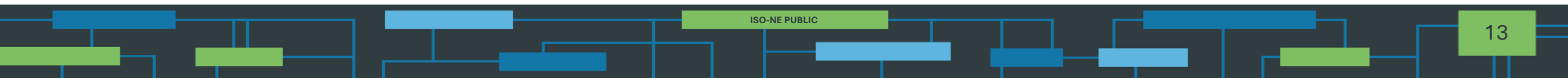
Where:

PPR is the Performance Payment Rate as defined in Section III.13.7.2.5 and Section III.15.8.2.5 of Market Rule 1.



FAP Redlines: SBE FA

SBE MW equals the Designated FCM Participant's average MW of System-Backed Exports across all Capacity Scarcity Conditions in the relevant group of months in the three Capacity Commitment Periods immediately preceding the current Capacity Commitment Period and those occurring in the months within the relevant group that are prior to the current month of the current Capacity Commitment Period, as the data becomes available; provided, however, that, beginning on October 1, 2026, data from Capacity Scarcity Conditions that occurred prior to October 1, 2026 shall no longer be used once data is available from a Capacity Scarcity Condition in the relevant group of months in a prior Capacity Commitment Period or a Capacity Scarcity Condition in the months within the relevant group that are prior to the current month of the current Capacity Commitment Period. Three separate groups of months shall be used for this purpose: June through September, December through February, and all other months.



FAP Redlines: SBE FA

Scarcity Hours equals the highest total number of hours in which a Capacity Scarcity Condition occurred during any month within the relevant group of months in the three Capacity Commitment Periods immediately preceding the current Capacity Commitment Period and those occurring in the months within the relevant group that are prior to the current month of the current Capacity Commitment Period, as the data becomes available. Three separate groups of months shall be used for this purpose: June through September, December through February, and all other months.

MEC (monthly export charges) equals System-Backed Export charges incurred in previous months, which have not yet been invoiced in instances where the MEC is a credit to the Designated FCM Participant or have not yet been invoiced and paid in instances where the MEC is a charge to the Designated FCM Participant. The MEC is estimated from the first day of the current month until it is replaced by the actual settled MEC value when settlement is complete.

PMEC (preliminary export charges) equals estimated System-Backed Export charges incurred in the current month. Where the estimated System-Backed Export charges shall be updated three (3) days after publication of the applicable report⁽¹⁾ on the Market Information Server.

(1) The ISO may update this text to state the name of the report.

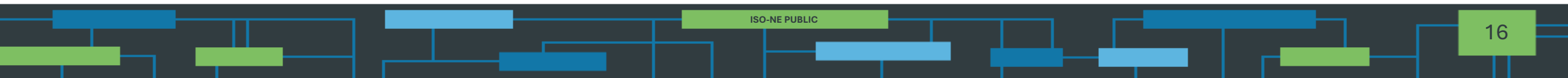
FAP Redlines: ABR

- ABR (average balancing ratio) is the duration-weighted average of all of the system-wide Capacity Balancing Ratios calculated for each system-wide Capacity Scarcity Condition occurring in the relevant group of months in the three Capacity Commitment Periods immediately preceding the current Capacity Commitment Period and those occurring in the months within the relevant group that are prior to the current month of the current Capacity Commitment Period, as the data becomes available. **For the purpose of calculating the ABR, all Capacity Balancing Ratios, including Capacity Balancing Ratios for Capacity Scarcity Conditions that occurred in past Capacity Commitment Periods or in the months within the relevant group that are prior to the current month of the current Capacity Commitment Period, shall be calculated utilizing the Capacity Balancing Ratio formula that is currently effective, as described in Section III.13.7.2.3 or Section III.15.8.2.3 of Market Rule 1⁽¹⁾.** Three separate groups of months shall be used for this purpose: June through September, December through February, and all other months. Until data exists to calculate this number, the temporary ABR for June through September shall equal 0.90; the temporary ABR for December through February shall equal 0.70; and the temporary ABR for all other months shall equal 0.60.

(1) The ISO proposes to include this sentence in the redlines for both the External Transactions and Balancing Ratio proposals. All other redlines will be included in the External Transactions proposal only. Each proposal will be filed with the Federal Energy Regulatory Commission separately.

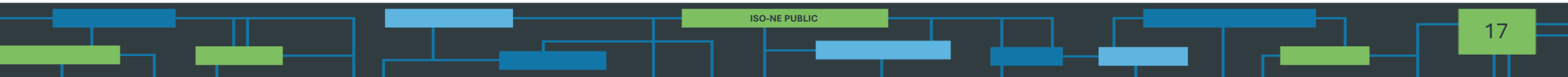
FAP Redlines: Administrative Changes

- Any Lead Market Participant, including any Provisional Member that is a Lead Market Participant, transacting in the Forward Capacity Market that is otherwise required to provide additional financial assurance under the ISO New England Financial Assurance Policy, **and any Market Participant with System-Backed Export transactions** (each a “Designated FCM Participant”), is required to provide additional financial assurance meeting the requirements of Section X below in the amounts described in this Section VII (such amounts being referred to in the ISO New England Financial Assurance Policy as the “FCM Financial Assurance Requirements”). If the Lead Market Participant for a Resource changes, then the new Lead Market Participant for the Resource shall become the Designated FCM Participant.



FAP Redlines: Administrative Changes

- a Market Participant's "Non-Hourly Requirements" at any time will be determined by averaging that Market Participant's Non-Hourly Charges but not include: (A) the amount due from or to such Market Participant for FTR transactions, (B) any amounts due from such Market Participant for the Forward Capacity Market **or System-Backed Export transactions**, (C) any amounts due under Section 14.1 of the RNA, (D) any amounts due for NEPOOL GIS API Fees, and (E) the amount of any Qualification Process Cost Reimbursement Deposit (including the annual true-up of that amount) due from such Market Participant) over the two most recently invoiced calendar months; provided that such Non-Hourly Requirements shall in no event be less than zero;



Conclusion

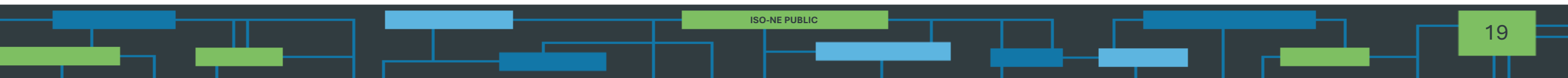
- The ISO is proposing FAP changes to mitigate the risk of a market participant defaulting on SBE charges incurred during CSCs
- The ISO is also proposing to change the FAP definition of ABR to include the 1.0 BR cap and utilize recalculated historical BR values based on the newly proposed BR formula
- The ISO will file the BR compliance proposal by July 21, 2026 and will propose an October 1, 2026 effective date
- The ISO plans to file the External Transactions proposal in July 2026, with an October 1, 2026 proposed effective date

Stakeholder Schedule

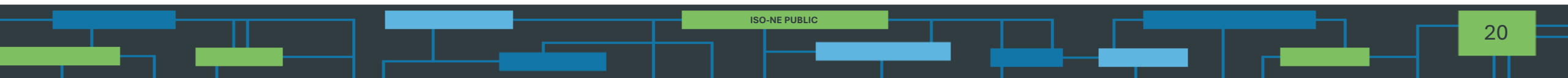
Stakeholder Committee and Date	Scheduled Project Milestone
Budget and Finance Subcommittee April 17, 2026	Introduce proposed Financial Assurance revisions for treatment of external transactions and Balancing Ratio cap under Pay-for-Performance
Budget and Finance Subcommittee May 8, 2026	Present associated FAP redlines
Budget and Finance Subcommittee June 5, 2026	Present related Billing Policy conforming change
Participants Committee June 16-18, 2026	Vote

The ISO will file the BR compliance proposal by July 21, 2026 and will propose an October 1, 2026 effective date.

The ISO plans to file the External Transactions proposal in July 2026, with an October 1, 2026 proposed effective date.



Questions



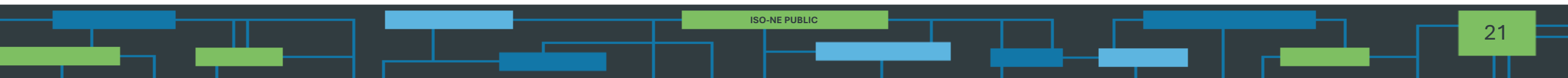
About the Presenter

Zach Shell

Supervisor, Market and Credit Risk

ISO New England

zshell@iso-ne.com



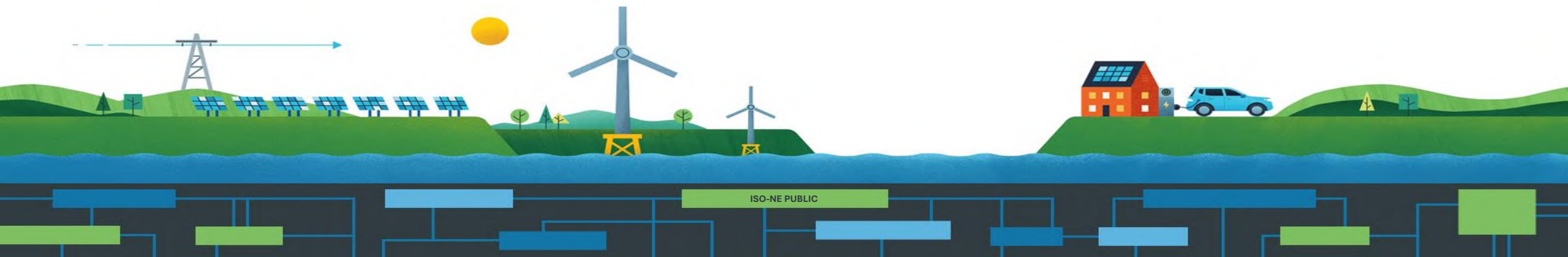


Pay-For-Performance Revisions: Conforming Change to the Billing Policy for External Transactions

*Proposed revision to the Billing Policy for inclusion of
System-Backed Export Charges*

Shelley Hall

FINANCIAL SYSTEMS & ACCOUNTING MANAGER



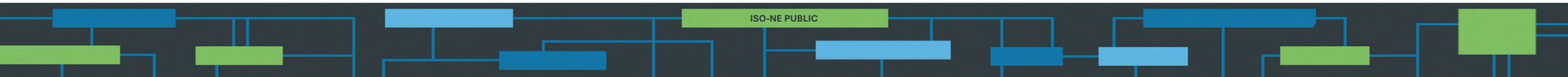
Pay-For-Performance Revisions: Conforming Change to the Billing Policy for External Transactions

NEPOOL PARTICIPANTS COMMITTEE
JUNE 16-18, 2026 SUMMER MEETING, AGENDA ITEM #7
Attachment H

WMPP ID:
190

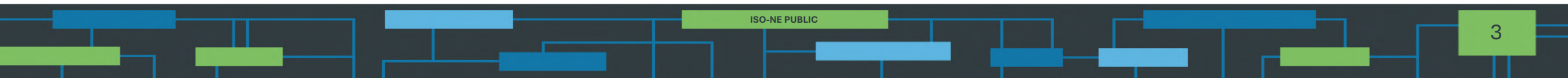
Proposed Effective Date: October 1, 2026

- The ISO has proposed changes to Pay-for-Performance (PFP), including charging System-Backed Exports (SBE) the Performance Payment Rate (PPR) during Capacity Scarcity Conditions (CSC)
- To conform with the External Transactions changes, the ISO proposes an update to the Billing Policy to include SBE Charges in Section 2.4 – Contents of Statements
- Today's discussion focuses on introducing the proposed conforming change



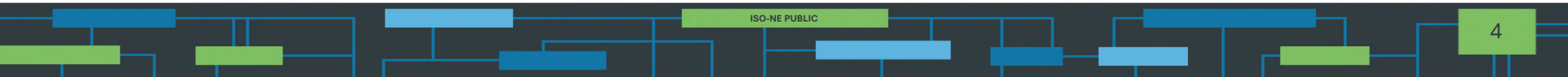
Background

- The ISO presented proposed changes to the PFP treatment of External Transactions such that SBEs would be charged the PPR during CSCs at the [March](#), [April](#), and [May](#) Markets Committee (MC) meetings
- The MC voted to recommend that the Participants Committee (PC) support the ISO's External Transactions proposal at the May MC meeting
- The ISO presented the proposed Financial Assurance Policy changes to conform with the proposed changes to the treatment of External Transactions at the [April](#) and [May](#) Budget and Finance Subcommittee (BFS) meetings
 - At the May BFS meeting, the ISO noted that a Billing Policy conforming change would be presented at the June BFS meeting



Proposal

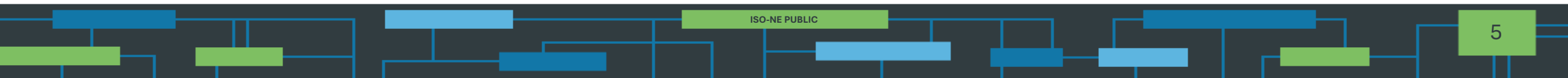
- As a component of PFP, SBE Charges will be billed to Market Participants as a Non-Hourly Charge in the Forward Capacity Market (FCM) Credit bill line
- The ISO is proposing a conforming change to the Billing Policy, Section 2.4(e), *Monthly Forward Capacity Market Charges and Payments*, to include SBE Charges



Summary of Proposed Tariff or Manual Changes^[1]

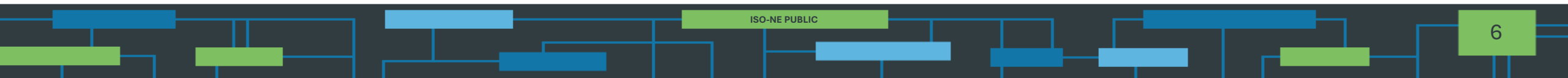
Section	Tariff or Manual Change	Reason for Change
Addition of SBE charges to Section 2.4 – Contents of Statements	“Each Statement for Hourly and Non-Hourly Charges will include all of the following line items that are applicable to the Covered Entity receiving such Statement for the period to which such Statement relates: e) <i>Monthly Forward Capacity Market Charges and Payments</i>. The Non-Hourly Charges owed by and the Payments for Non-Hourly Charges owed to the Covered Entity as a result of Capacity Performance Payments, System-Backed Export Charges, and other transactions in the Forward Capacity Market.”	Addition of SBE charges as part of the non-hourly charge in the Forward Capacity Market billing line to align with External Transactions treatment in new PFP design

^[1] Section 2.4 redlines are being provided with these materials



Conclusion

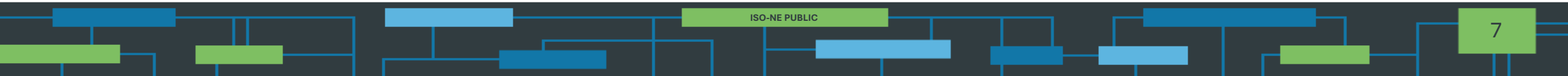
- The ISO is proposing a conforming change to Section 2.4(e) of the Billing Policy to include SBE Charges in Monthly Forward Capacity Market Charges and Payments
- The ISO plans to file the proposed Billing Policy changes in July 2026 with an October 1, 2026 proposed effective date



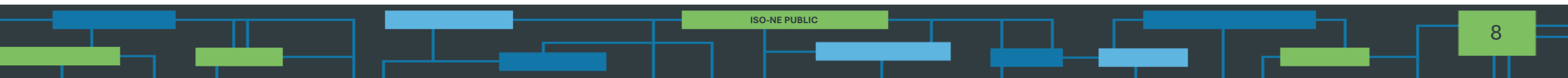
Stakeholder Schedule

Stakeholder Committee and Date	Scheduled Project Milestone
Budget and Finance Subcommittee June 5, 2026	Introduce Section 2.4(e) proposed Billing Policy change for External Transactions
Participants Committee June 16-18, 2026	Vote

Note: The ISO plans to file the External Transactions proposal in July 2026, with an October 1, 2026 proposed effective date.



Questions



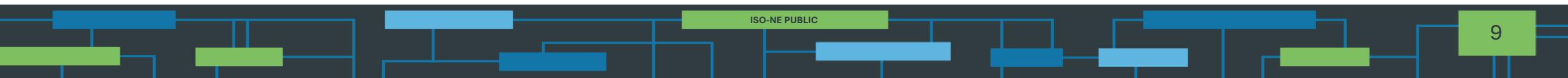
About the Presenter

Shelley Hall

Financial Systems & Accounting Manager

ISO New England

shehall@iso-ne.com



MEMORANDUM

TO: NEPOOL Participants Committee Members and Alternates

FROM: Rosendo Garza, NEPOOL Counsel

DATE: June 9, 2026

RE: Compliance Proposal to Cap the Balancing Ratio

At its June 2026 Summer Meeting, the Participants Committee will be asked to support the ISO's package of Tariff revisions proposed in response to the FERC's order requiring the ISO to cap the Capacity Balancing Ratio¹ (the Balancing Ratio Compliance Proposal). This memorandum provides an overview of the Compliance Proposal and includes the following attachments:

- Attachment A: Tariff Section I.2.2 Redline Sheets
- Attachment B: Market Rule 1 Redline Sheets
- Attachment C: Financial Assurance Policy Redline Sheets
- Attachment D: ISO-NE's Markets Committee March 10–12, 2026 Presentation
- Attachment E: ISO-NE's Markets Committee April 14–16, 2026 Presentation
- Attachment F: ISO-NE's Budget & Finance Subcommittee May 8, 2026 Presentation

BACKGROUND

In 2025, the New England Power Generators Association (NEPGA) filed a complaint² with the FERC arguing that certain Tariff provisions governing the Balancing Ratio³ and the allocation of stop-losses in the Pay-for-Performance (PFP) design were unjust and unreasonable. NEPGA argued that the provisions effectively held resources with Capacity Supply Obligations to a performance standard greater than their CSO during Capacity Scarcity Conditions (CSCs). The FERC granted in part and denied in part the complaint.

In granting the complaint in part, the FERC held that the ISO's uncapped Balancing Ratio was unjust and unreasonable because resources with CSOs could be subject to Capacity Performance Payment charges even when they were providing their maximum possible physical output during CSCs. In denying the remainder of the complaint, the FERC found that NEPGA had failed to demonstrate that the ISO's allocation methodology for the stop-loss amounts was

¹ *New Eng. Power Generators Ass'n v. ISO New Eng. Inc.*, 194 FERC ¶ 61,052 (2026).

² NEPGA's complaint was filed subsequent to a June 2025 Capacity Scarcity Condition (CSC). During that event, the Balancing Ratio exceeded 1.0, averaging 1.031, over the 37 intervals of the event.

³ The Balancing Ratio is the sum of load and the reserve requirement divided by the total system CSO and is used to determine a capacity resource's share-of-system obligation during a CSC.

unjust, unreasonable, or unduly discriminatory or preferential. The FERC therefore directed the ISO to cap the Balancing Ratio at 1.0 and submit any necessary conforming Tariff modifications.

Markets Committee Review – Market Rule 1 Revisions

As described further in Attachments D and E, the Balancing Ratio Compliance Proposal revises the PFP framework to cap the Balancing Ratio at 1.0 and make related conforming changes to the allocation of Capacity Performance Payments. Attachment B contains the Market Rule 1 revisions necessary to implement these changes.

The ISO introduced its proposal at the March Markets Committee meeting and continued discussions with stakeholders during subsequent committee meetings. At its May 12–14, 2026 meeting, the Markets Committee unanimously voted to recommend Participants Committee support for the Market Rule 1 revisions.⁴

Budget & Finance Subcommittee (B&F) Review – Financial Assurance Policy (FAP) Revisions

The Balancing Ratio Compliance Proposal also includes conforming revisions to the FAP. Specifically, the FAP revisions would update the definition of Average Balancing Ratio (ABR), which is used in the Forward Capacity Market financial assurance calculation, so that historical Balancing Ratios used in the ABR calculation are capped at 1.0, consistent with the FERC’s order.⁵ Attachment F contains more information on the changes to the FAP.

The ISO introduced the proposed FAP revisions at the April 17, 2026 B&F meeting and presented related redlines at the May 8, 2026 B&F meeting. No Subcommittee member present at either meeting expressed opposition to, or concerns regarding, the proposed FAP revisions.

PARTICIPANTS COMMITTEE ACTION

The following forms of resolution may be used for Participants Committee action, voted either individually or in a single combined vote⁶:

⁴ Two abstentions were noted, one in the End User Sector and one in the Generation Sector.

⁵ The ISO’s related External Transactions Proposal (see Item 7) would separately revise the Balancing Ratio formula to subtract system-backed exports from the numerator. Because the ABR calculation relies on historical Capacity Balancing Ratios, the FAP redlines for this Compliance Proposal are also part of the External Transactions Proposal.

⁶ For the Participants Committee to approve the Balancing Ratio Compliance Proposal, the Markets Committee-recommended changes to Section I.2.2 and Market Rule 1 require a 60% Vote in favor, and the proposed FAP revisions require a 66.67% Vote in favor.

RESOLVED, that the Participants Committee supports the Tariff Section I.2.2 and Market Rule 1 revisions for the ISO's Balancing Ratio Compliance Proposal, as recommended by the Markets Committee at its May 2026 meeting and circulated in advance of this meeting, together with [any changes agreed to by the Participants Committee at this meeting and] such non-substantive changes as may be approved by the Chair and Vice-Chair of the Markets Committee.

RESOLVED, that the Participants Committee supports revisions to the ISO New England Financial Assurance Policy for the ISO's Balancing Ratio Compliance Proposal, as circulated in advance of this meeting, together with [any changes agreed to by the Participants Committee at this meeting and] such non-substantive changes as may be approved by the Chair of the Budget & Finance Subcommittee.

I.2 Rules of Construction; Definitions

I.2.1. Rules of Construction:

In this Tariff, unless otherwise provided herein:

- (a) words denoting the singular include the plural and vice versa;
- (b) words denoting a gender include all genders;
- (c) references to a particular part, clause, section, paragraph, article, exhibit, schedule, appendix or other attachment shall be a reference to a part, clause, section, paragraph, or article of, or an exhibit, schedule, appendix or other attachment to, this Tariff;
- (d) the exhibits, schedules and appendices attached hereto are incorporated herein by reference and shall be construed with an as an integral part of this Tariff to the same extent as if they were set forth verbatim herein;
- (e) a reference to any statute, regulation, proclamation, ordinance or law includes all statutes, regulations, proclamations, amendments, ordinances or laws varying, consolidating or replacing the same from time to time, and a reference to a statute includes all regulations, policies, protocols, codes, proclamations and ordinances issued or otherwise applicable under that statute unless, in any such case, otherwise expressly provided in any such statute or in this Tariff;
- (f) a reference to a particular section, paragraph or other part of a particular statute shall be deemed to be a reference to any other section, paragraph or other part substituted therefor from time to time;
- (g) a definition of or reference to any document, instrument or agreement includes any amendment or supplement to, or restatement, replacement, modification or novation of, any such document, instrument or agreement unless otherwise specified in such definition or in the context in which such reference is used;
- (h) a reference to any person (as hereinafter defined) includes such person's successors and permitted assigns in that designated capacity;
- (i) any reference to "days" shall mean calendar days unless "Business Days" (as hereinafter defined) are expressly specified;
- (j) if the date as of which any right, option or election is exercisable, or the date upon which any amount is due and payable, is stated to be on a date or day that is not a Business Day, such right, option or election may be exercised, and such amount shall be deemed due and payable, on the next succeeding Business Day with the same effect as if the same was exercised or made on such date or day (without, in the case of any such payment, the payment or accrual of any interest or

other late payment or charge, provided such payment is made on such next succeeding Business Day);

- (k) words such as “hereunder,” “hereto,” “hereof” and “herein” and other words of similar import shall, unless the context requires otherwise, refer to this Tariff as a whole and not to any particular article, section, subsection, paragraph or clause hereof; and a reference to “include” or “including” means including without limiting the generality of any description preceding such term, and for purposes hereof the rule of *ejusdem generis* shall not be applicable to limit a general statement, followed by or referable to an enumeration of specific matters, to matters similar to those specifically mentioned.

I.2.2. Definitions:

In this Tariff, the terms listed in this section shall be defined as described below:

Above-Threshold Offer Segment is the total MW quantity of a Capacity Offer that is priced above the Capacity Offer Price Threshold, whether such MW quantity is delimited by only one price-quantity pair or multiple price-quantity pairs submitted as part of the Capacity Offer pursuant to Section III.15.4.1.

Active Demand Capacity Resource is one or more Demand Response Resources located within the same Dispatch Zone, that is registered with the ISO, assigned a unique resource identification number by the ISO, and participates in the Forward or Annual Capacity Market to fulfill a Market Participant’s Capacity Supply Obligation pursuant to Section III.13 or Section III.15 of Market Rule 1.

Actual Capacity Provided is the measure of capacity provided during a Capacity Scarcity Condition, as described in Section III.13.7.2.2 or Section III.15.8.2.2 of Market Rule 1.

Actual Load is the consumption at the Retail Delivery Point for the hour.

Additional Resource Blackstart O&M Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Additional Resource Specified-Term Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Capacity Network Import Capability (CNI Capability) is as defined in Section I of Schedule 25 of the OATT.

Capacity Network Import Interconnection Service (CNI Interconnection Service) is as defined in Section I of Schedule 25 of the OATT.

Capacity Network Resource (CNR) is defined in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

Capacity Network Resource Interconnection Service (CNR Interconnection Service) is defined in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

Capacity Offer is an offer submitted for inclusion in the Annual Capacity Auction as set forth in Section III.15.4.1 of Market Rule 1.

Capacity Offer Floor Price is defined in Section III.A.21.3 of Market Rule 1.

Capacity Offer Price Threshold (COPT) is the price specified in Section III.A.22.2.1 of Market Rule 1 associated with the submission, review, and mitigation of prices specified in Capacity Offers submitted for the Annual Capacity Auction.

Capacity Offer Review Submission Deadline is the deadline described in the Capacity Auction Calendar by which proposed Capacity Offers and accompanying documentation must be submitted to the Internal Market Monitor in accordance with Section III.A.22.2.2.

~~**Capacity Performance Bilateral** is a transaction for transferring Capacity Performance Score, as described in Section III.13.5.3 or Section III.15.6.3 of Market Rule 1.~~

Capacity Performance Payment is the performance-dependent portion of revenue received in the Forward Capacity Market, as described in Section III.13.7.2 or Section III.15.8.2 of Market Rule 1.

Capacity Performance Payment Rate is a rate used in calculating Capacity Performance Payments, as described in Section III.13.7.2.5 or Section III.15.8.2.5 of Market Rule 1.

Table of Contents

III.1	Market Operations.	
III.1.1	Introduction.	
III.1.2	[Reserved.]	
III.1.3	Definitions.	
	III.1.3.1	[Reserved.]
	III.1.3.2	[Reserved.]
	III.1.3.3	[Reserved.]
III.1.4	Requirements for Certain Transactions.	
	III.1.4.1	ISO Settlement of Certain Transactions.
	III.1.4.2	Transactions Subject to Requirements of Section III.1.4.
	III.1.4.3	Requirements for Section III.1.4 Conforming Transactions.
III.1.5	Resource Auditing.	
III.1.5.1.	Claimed Capability Audits.	
III.1.5.1.1	General Audit Requirements.	
III.1.5.1.2	Establish Claimed Capability Audit.	
III.1.5.1.3	Seasonal Claimed Capability Audits.	
III.1.5.1.3.1	Seasonal DR Audits.	
III.1.5.1.4	ISO-Initiated Claimed Capability Audits.	
III.1.5.2.	ISO-Initiated Parameter Auditing.	
III.1.5.3	Reactive Capability Audits.	
III.1.6	[Reserved.]	
	III.1.6.1	[Reserved.]
	III.1.6.2	[Reserved.]
	III.1.6.3	[Reserved.]
	III.1.6.4	ISO New England Manuals and ISO New England Administrative Procedures.
III.1.7	General.	
	III.1.7.1	Provision of Market Data to the Commission.

III.13.4.2.1.2.2.1.2	Winter ARA Qualified Capacity.
III.13.4.2.1.2.2.2	Intermittent Power Resources.
III.13.4.2.1.2.2.2.1	Summer ARA Qualified Capacity.
III.13.4.2.1.2.2.2.2	Winter ARA Qualified Capacity.
III.13.4.2.1.2.2.3	Import Capacity Resources.
III.13.4.2.1.2.2.3.1	Import Capacity Resources Backed by an External Control Area.
III.13.4.2.1.2.2.3.2	Import Capacity Resources Backed by One or More External Resources.
III.13.4.2.1.2.2.4	Demand Capacity Resources.
III.13.4.2.1.2.2.4.1	Summer ARA Qualified Capacity.
III.13.4.2.1.2.2.4.2	Winter ARA Qualified Capacity.
III.13.4.2.1.2.2.5	Distributed Energy Capacity Resources.
III.13.4.2.1.2.2.5.1	Summer ARA Qualified Capacity.
III.13.4.2.1.2.2.5.2	Winter ARA Qualified Capacity.
III.13.4.2.1.3	Adjustment for Significant Decreases in Capacity.
III.13.4.2.1.4	Amount of Capacity That May Be Submitted in a Supply Offer in a Monthly Reconfiguration Auction.
III.13.4.2.1.5	ISO Review of Supply Offers.
III.13.4.2.2	Demand Bids in Reconfiguration Auctions.
III.13.4.3	ISO Participation in Reconfiguration Auctions.
III.13.4.4	Clearing Offers and Bids in Reconfiguration Auctions.
III.13.4.5	Annual Reconfiguration Auctions.
III.13.4.5.1	Timing of Annual Reconfiguration Auctions.
III.13.4.5.2	Acceleration of Annual Reconfiguration Auction.
III.13.4.6	[Reserved.]
III.13.4.7	Monthly Reconfiguration Auctions.
III.13.4.8	Adjustment to Capacity Supply Obligations.
III.13.5	Bilateral Contracts in the Forward Capacity Market.
III.13.5.1	Capacity Supply Obligation Bilaterals.

- III.13.5.1.1 Process for Approval of Capacity Supply Obligation Bilaterals.
- III.13.5.1.1.1 Timing of Submission and Prior Notification to the ISO.
- III.13.5.1.1.2 Application.
- III.13.5.1.1.3 ISO Review.
- III.13.5.1.1.4 Approval.
- III.13.5.2 Capacity Load Obligations Bilaterals.
- III.13.5.2.1 Process for Approval of Capacity Load Obligation Bilaterals.
- III.13.5.2.1.1 Timing.
- III.13.5.2.1.2 Application.
- III.13.5.2.1.3 ISO Review.
- III.13.5.2.1.4 Approval.
- III.13.5.3 ~~—— [Reserved.] Capacity Performance Bilaterals.~~
- ~~III.13.5.3.1 ——— Eligibility.~~
- ~~III.13.5.3.2 ——— Submission of Capacity Performance Bilaterals.~~
- ~~III.13.5.3.2.1 ——— Timing.~~
- ~~III.13.5.3.2.2 ——— Application.~~
- ~~III.13.5.3.2.3 ——— ISO Review.~~
- ~~III.13.5.3.3 ——— Effect of Capacity Performance Bilateral.~~
- III.13.5.4 Annual Reconfiguration Transactions.
- III.13.5.4.1 Timing of Submission.
- III.13.5.4.2 Components of an Annual Reconfiguration Transaction.
- III.13.5.4.3 Settlement of Annual Reconfiguration Transactions.
- III.13.6 Rights and Obligations.
- III.13.6.1 Resources with Capacity Supply Obligations.
- III.13.6.1.1 Generating Capacity Resources with Capacity Supply Obligations.
- III.13.6.1.1.1 Energy Market Offer Requirements.
- III.13.6.1.1.2 Requirement that Offers Reflect Accurate Generating Capacity Resource Operating Characteristics.

- III.15.3.4.2 Annual Qualified Capacity
- III.15.3.4.3 Monthly Qualified Capacity
- III.15.3.5 Qualified Capacity of Distributed Energy Capacity Resources
 - III.15.3.5.1 Summer and Winter Qualified Capacity
 - III.15.3.5.2 Annual Qualified Capacity
 - III.15.3.5.3 Monthly Qualified Capacity
- III.15.3.6 Adjustment for Significant Decreases in Capacity
- III.15.3.7 Resources Having a Higher Summer Qualified Capacity than Winter Qualified Capacity
- III.15.4 Annual Capacity Auction
 - III.15.4.1 Capacity Offers
 - III.15.4.2 Conduct of the Annual Capacity Auction
 - III.15.4.2.1 Replacement of Specified Prices for Mitigation Purposes
 - III.15.4.2.2 Clearing of the Annual Capacity Auction
 - III.15.4.2.3 Results of the Annual Capacity Auction
 - III.15.4.2.4 Additional Clearing of Auction in the Event of Cleared Proxy Offers
 - III.15.4.3 Publication of Annual Capacity Auction Results
- III.15.5 Monthly Reconfiguration Auctions
 - III.15.5.1 Capacity Zones Included in Monthly Reconfiguration Auctions
 - III.15.5.2 Participation in Monthly Reconfiguration Auctions
 - III.15.5.2.1 Supply Offers in Monthly Reconfiguration Auctions
 - III.15.5.2.2 Demand Bids in Monthly Reconfiguration Auctions
 - III.15.5.3 Clearing Offers and Bids in Monthly Reconfiguration Auctions
 - III.15.5.4 Conduct of Monthly Reconfiguration Auctions
 - III.15.5.5 Adjustment to Capacity Supply Obligations
- III.15.6 Bilateral Capacity Contracts
 - III.15.6.1 Capacity Supply Obligation Bilaterals.
 - III.15.6.1.1 Terms of and Participation in Capacity Supply Obligation Bilaterals

III.15.6.1.2 Timing of Submission and Prior Notification to the ISO

III.15.6.1.3 Contents of Submission to the ISO

III.15.6.1.4 ISO Review

III.15.6.1.5 Approval

III.15.6.2 Capacity Load Obligations Bilaterals

III.15.6.2.1 Terms of and Participation in Capacity Load Obligation Bilaterals

III.15.6.2.2 Timing of Submission to the ISO

III.15.6.2.3 Contents of Submission to the ISO

III.15.6.2.4 ISO Review

III.15.6.2.5 Approval

~~III.15.6.3 Capacity Performance Bilaterals~~

~~III.15.6.3.1 Terms of and Participation in Capacity Performance Bilaterals~~

~~III.15.6.3.2 Timing of Submission to the ISO~~

~~III.15.6.3.3 Contents of Submission to the ISO~~

~~III.15.6.3.4 ISO Review~~

~~III.15.6.3.5 Effect of Capacity Performance Bilateral~~

III.15.7 Obligations of Capacity Suppliers

III.15.7.1 Resources with Capacity Supply Obligations

III.15.7.1.1 Generating Capacity Resources with Capacity Supply Obligations

III.15.7.1.2 Import Capacity Resources with Capacity Supply Obligations

III.15.7.1.3 Intermittent Power Resources with Capacity Supply Obligations

III.15.7.1.4 [Reserved.]

III.15.7.1.5 Demand Capacity Resources with Capacity Supply Obligations

III.15.7.1.6 DNE Dispatchable Generator

III.15.7.1.7 Distributed Energy Capacity Resources with Capacity Supply Obligations

III.15.7.2 Resources without a Capacity Supply Obligation

STANDARD MARKET DESIGN

III.1 Market Operations

III.1.1 Introduction.

This Market Rule 1 sets forth the scheduling, other procedures, and certain general provisions applicable to the operation of the New England Markets within the New England Control Area. The ISO shall operate the New England Markets in compliance with NERC, NPCC and ISO reliability criteria. The ISO is the Counterparty for agreements and transactions with its Customers (including assignments involving Customers), including bilateral transactions described in Market Rule 1, and sales to the ISO and/or purchases from the ISO of energy, reserves, Ancillary Services, capacity, demand/load response, FTRs and other products, paying or charging (if and as applicable) its Customers the amounts produced by the pertinent market clearing process or through the other pricing mechanisms described in Market Rule 1. The bilateral transactions to which the ISO is the Counterparty (subject to compliance with the requirements of Section III.1.4) include, but are not limited to, Internal Bilaterals for Load, Internal Bilaterals for Market for Energy, Annual Reconfiguration Transactions, Capacity Supply Obligation Bilaterals, Capacity Load Obligation Bilaterals, [Capacity Performance Bilaterals](#), and the transactions described in Sections III.9.4.1 (internal bilateral transactions that transfer Forward Reserve Obligations), and III.13.1.6 (Self-Supplied FCA Resources). Notwithstanding the foregoing, the ISO will not act as Counterparty for the import into the New England Control Area, for the use of Publicly Owned Entities, of: (1) energy, capacity, and ancillary products associated therewith, to which the Publicly Owned Entities are given preference under Articles 407 and 408 of the project license for the New York Power Authority's Niagara Project; and (2) energy, capacity, and ancillary products associated therewith, to which Publicly Owned Entities are entitled under Article 419 of the project license for the New York Power Authority's Franklin D. Roosevelt – St. Lawrence Project. This Market Rule 1 addresses each of the three time frames pertinent to the daily operation of the New England Markets: "Pre-scheduling" as specified in Section III.1.9, "Scheduling" as specified in III.1.10, and "Dispatch" as specified in III.1.11. This Market Rule 1 became effective on February 1, 2005.

III.1.2 [Reserved.]

III.1.3 Definitions.

Whenever used in Market Rule 1, in either the singular or plural number, capitalized terms shall have the meanings specified in Section I of the Tariff. Terms used in Market Rule 1 that are not defined in Section

I shall have the meanings customarily attributed to such terms by the electric utility industry in New England or as defined elsewhere in the ISO New England Filed Documents. Terms used in Market Rule 1 that are defined in Section I are subject to the 60% Participant Vote threshold specified in Section 11.1.2 of the Participants Agreement.

III.1.3.1 [Reserved.]

III.1.3.2 [Reserved.]

III.1.3.3 [Reserved.]

III.1.4 Requirements for Certain Transactions.

III.1.4.1 ISO Settlement of Certain Transactions.

The ISO will settle, and act as Counterparty to, the transactions described in Section III.1.4.2 if the transactions (and their related transactions) conform to, and the transacting Market Participants comply with, the requirements specified in Section III.1.4.3.

III.1.4.2 Transactions Subject to Requirements of Section III.1.4.

Transactions that must conform to the requirements of Section III.1.4 include: Internal Bilaterals for Load, Internal Bilaterals for Market for Energy, Annual Reconfiguration Transactions, Capacity Supply Obligation Bilaterals, Capacity Load Obligation Bilaterals, ~~Capacity Performance Bilaterals~~, and the transactions described in Sections III.9.4.1 (internal bilateral transactions that transfer Forward Reserve Obligations), and III.13.1.6 (Self-Supplied FCA Resources). The foregoing are referred to collectively as “Section III.1.4 Transactions,” and individually as a “Section III.1.4 Transaction.” Transactions that conform to the standards are referred to collectively as “Section III.1.4 Conforming Transactions,” and individually as a “Section III.1.4 Conforming Transaction.”

III.1.4.3 Requirements for Section III.1.4 Conforming Transactions.

(a) To qualify as a Section III.1.4 Conforming Transaction, a Section III.1.4 Transaction must constitute an exchange for an off-market transaction (a “Related Transaction”), where the Related Transaction:

- (i) is not cleared or settled by the ISO as Counterparty;
- (ii) is a spot, forward or derivatives contract that contemplates the transfer of energy or a MW obligation to or from a Market Participant;

III.13.5. Bilateral Contracts in the Forward Capacity Market.

Market Participants shall be permitted to enter into Annual Reconfiguration Transactions, Capacity Supply Obligation Bilaterals, [and](#) Capacity Load Obligation Bilaterals [and](#) [Capacity Performance Bilaterals](#) in accordance with this Section III.13.5, with the ISO serving as Counterparty in each such transaction. Market Participants may not offset a Capacity Load Obligation with a Capacity Supply Obligation.

III.13.5.1. Capacity Supply Obligation Bilaterals.

Capacity Supply Obligation Bilaterals are available for monthly periods. The qualification of resources subject to a Capacity Supply Obligation Bilateral is determined in the same manner as the qualification of resources is determined for reconfiguration auctions as specified in Section III.13.4.2.

A resource having a Capacity Supply Obligation seeking to shed that obligation (Capacity Transferring Resource) may enter into a bilateral transaction to transfer its Capacity Supply Obligation, in whole or in part (Capacity Supply Obligation Bilateral), to a resource, or portion thereof, having Qualified Capacity for that Capacity Commitment Period that is not already obligated (Capacity Acquiring Resource), subject to the following limitations.

- (a) A Capacity Supply Obligation Bilateral must be coterminous with a calendar month.
- (b) A Capacity Supply Obligation Bilateral may not transfer a Capacity Supply Obligation amount that is greater than the monthly Capacity Supply Obligation of the Capacity Transferring Resource. A Capacity Supply Obligation Bilateral may not transfer a Capacity Supply Obligation amount that is greater than the amount of unobligated Qualified Capacity (that is, Qualified Capacity as determined in the most recent Forward Capacity Auction or reconfiguration auction qualification process that is not subject to a Capacity Supply Obligation) of the Capacity Acquiring Resource during the month covered by the Capacity Supply Obligation Bilateral, as determined in the qualification process for the most recent Forward Capacity Auction or annual reconfiguration auction prior to the submission of the Capacity Supply Obligation Bilateral to the ISO.
- (c) A Capacity Supply Obligation Bilateral may not transfer a Capacity Supply Obligation to a Capacity Acquiring Resource where that Capacity Acquiring Resource's unobligated Qualified Capacity is unobligated as a result of an Export Bid or Administrative Export De-List Bid that cleared in the Forward Capacity Auction.

Obligation of the Capacity Load Obligation Acquiring Participant in the specified Capacity Zone shall be increased by the amount set forth in the Capacity Load Obligation Bilateral.

III.13.5.3. [Reserved.]Capacity Performance Bilaterals.

~~A resource's Capacity Performance Score during a Capacity Scarcity Condition may be adjusted by entering into a Capacity Performance Bilateral as described in this Section III.13.5.3.~~

III.13.5.3.1. Eligibility.

~~If a resource has a Capacity Performance Score that is greater than zero in a five minute interval that is subject to a Capacity Scarcity Condition, that resource may transfer all or some of that Capacity Performance Score to another resource for that same five minute interval so long as both resources were subject to the same Capacity Scarcity Condition.~~

III.13.5.3.2. Submission of Capacity Performance Bilaterals.

~~The Lead Market Participant for a resource having a Capacity Performance Score that is greater than zero in a five minute interval that is subject to a Capacity Scarcity Condition may submit a Capacity Performance Bilateral to the ISO assigning all or a portion of its Capacity Performance Score for that interval to another resource, subject to the eligibility requirements specified in Section III.13.5.3.1. The Capacity Performance Bilateral must be confirmed by the Lead Market Participant for the resource receiving the Capacity Performance Score.~~

III.13.5.3.2.1. Timing.

~~A Capacity Performance Bilateral must be submitted in accordance with resettlement provisions as described in ISO New England Manuals. However, to be included in the initial settlement of payments and charges associated with the Forward Capacity Market for the month associated with the Capacity Performance Bilateral, a Capacity Performance Bilateral must be submitted to the ISO no later than 12:00 pm on the second Business Day after the end of that month, or at such later deadline as specified by the ISO upon notice to Market Participants (though a Capacity Performance Bilateral may be revised by the parties to the transaction throughout the resettlement process).~~

III.13.5.3.2.2. Application.

~~The submission of a Capacity Performance Bilateral to the ISO shall include the following: (i) the resource identification number for the resource transferring its Capacity Performance Score; (ii) the resource identification number for the resource receiving the Capacity Performance Score; (iii) the MW~~

~~amount of Capacity Performance Score being transferred; (iv) the specific five minute interval or intervals for which the Capacity Performance Bilateral applies.~~

~~III.13.5.3.2.3. ISO Review.~~

~~The ISO shall review the information provided in submission of the Capacity Performance Bilateral, and shall reject the Capacity Performance Bilateral if any of the provisions of this Section III.13.5.3 are not met.~~

~~III.13.5.3.3. Effect of Capacity Performance Bilateral.~~

~~A Capacity Performance Bilateral does not affect in any way either party's Capacity Supply Obligation or the rights and obligations associated therewith. The sole effect of a Capacity Performance Bilateral is to modify the Capacity Performance Scores of the transferring and receiving resources for the Capacity Scarcity Conditions subject to the Capacity Performance Bilateral for purposes of calculating Capacity Performance Payments as described in Section III.13.7.2.~~

III.13.5.4 Annual Reconfiguration Transactions.

Annual Reconfiguration Transactions are available for annual reconfiguration auctions for Capacity Commitment Periods beginning on or after June 1, 2020, except that Annual Reconfiguration Transactions are not available for the first annual reconfiguration auction for the Capacity Commitment Period beginning on June 1, 2020.

III.13.5.4.1 Timing of Submission.

The Lead Market Participant or Project Sponsor for either a Capacity Transferring Resource or a Capacity Acquiring Resource may submit an Annual Reconfiguration Transaction to the ISO in accordance with posted schedules. The ISO will issue a schedule of the submittal windows for Annual Reconfiguration Transactions as soon as practicable after the issuance of Forward Capacity Auction results. An Annual Reconfiguration Transaction must be confirmed by the party other than the party submitting the Annual Reconfiguration Transaction to the ISO no later than the end of the relevant submittal window.

III.13.5.4.2 Components of an Annual Reconfiguration Transaction.

The submission of an Annual Reconfiguration Transaction must include the following:

1. the resource identification number of the Capacity Transferring Resource;
2. the applicable Capacity Commitment Period;
- (3) the resource identification number of the Capacity Acquiring Resource, and;

III.13.7. Performance, Payments and Charges in the FCM.

Revenue in the Forward Capacity Market for resources providing capacity shall be composed of Capacity Base Payments as described in Section III.13.7.1 and Capacity Performance Payments as described in Section III.13.7.2, adjusted as described in Section III.13.7.3 and Section III.13.7.4. Market Participants with a Capacity Load Obligation will be subject to charges as described in Section III.13.7.5.

In the event of a change in the Lead Market Participant for a resource that has a Capacity Supply Obligation, the Capacity Supply Obligation shall remain associated with the resource and the new Lead Market Participant for the resource shall be bound by all provisions of this Section III.13 arising from such Capacity Supply Obligation. The Lead Market Participant for the resource at the start of an Obligation Month shall be responsible for all payments and charges associated with that resource in that Obligation Month.

III.13.7.1. Capacity Base Payments.

Resources acquiring or shedding a Capacity Supply Obligation for the Obligation Month shall receive a Capacity Base Payment for the Obligation Month reflecting the payments and charges described in Section III.13.7.1.1.

III.13.7.1.1. Payments and Charges Reflecting Capacity Supply Obligations.

Each resource that has: (i) cleared in a Forward Capacity Auction, except for the portion of resources designated as Self-Supplied FCA Resources; (ii) cleared in a reconfiguration auction; or (iii) entered into a Capacity Supply Obligation Bilateral shall be entitled to a monthly payment or charge during the Capacity Commitment Period. Each monthly payment and charge listed in Section III.13.7.1.1 (a) through (d) below will be divided by the number of days in the month to derive a daily settlement value.

(a) **Forward Capacity Auction.** For a resource whose offer has cleared in a Forward Capacity Auction, the monthly capacity payment shall equal the product of its cleared capacity and the Capacity Clearing Price in the Capacity Zone in which the resource is located as adjusted by applicable indexing for resources with additional Capacity Commitment Period elections pursuant to Section III.13.1.1.2.2.4 in the manner described below. For a resource that has elected to have the Capacity Clearing Price and the Capacity Supply Obligation apply for more than one Capacity Commitment Period, payments associated with the Capacity Supply Obligation and Capacity Clearing Price (indexed using the Handy-Whitman Index of Public Utility Construction Costs in effect as of December 31 of the year preceding the Capacity Commitment Period) shall continue to apply after the Capacity Commitment Period associated

curtailment as described in Section III.8.3, a Real-Time demand reduction shall also be calculated for intervals in which the associated Demand Response Resource or Demand Response Distributed Energy Resource Aggregation does not receive a non-zero Dispatch Instruction; (2) in the case of a Demand Response Asset or Distributed Energy Resource associated with a Demand Response Distributed Energy Resource Aggregation that is on a forced or scheduled curtailment as described in Section III.8.3, the minuend in the calculation described in Section III.8.4 shall be the unadjusted Demand Response Baseline of the Demand Response Asset or Distributed Energy Resource associated with a Demand Response Distributed Energy Resource Aggregation; and (3) the resulting MWhs of reduction, other than the MWhs associated with Net Supply, shall be increased by average avoided peak transmission and distribution losses.

III.13.7.2.3 Capacity Balancing Ratio.

For each five-minute interval in which a Capacity Scarcity Condition exists, the ISO shall calculate a Capacity Balancing Ratio using the following formula:

$$(\text{Load} + \text{Reserve Requirement}) / \text{Total Capacity Supply Obligation}$$

provided, however, that the Capacity Balancing Ratio shall not exceed a value of 1.0.

(a) If the Capacity Scarcity Condition is a result of a violation of the Minimum Total Reserve Requirement such that the associated system-wide Reserve Constraint Penalty Factor pricing applies, then the terms used in the formula above shall be calculated as follows:

Load = the total amount of Actual Capacity Provided (excluding applicable Real-Time Reserve Designations) from all resources in the New England Control Area during the interval (with the Actual Capacity Provided of Energy Efficiency measures being zero, as specified in Section III.13.7.2.2(c)(i)).

Reserve Requirement = the Minimum Total Reserve Requirement during the interval.

Total Capacity Supply Obligation = the total amount of Capacity Supply Obligations in the New England Control Area during the interval, excluding the Capacity Supply Obligations associated with Energy Efficiency measures.

(b) If the Capacity Scarcity Condition is a result of a violation of the Ten-Minute Reserve Requirement such that the associated system-wide Reserve Constraint Penalty Factor pricing applies, then the terms used in the formula above shall be calculated as follows:

Load = the total amount of Actual Capacity Provided (excluding applicable Real-Time Reserve Designations) from all resources in the New England Control Area during the interval (with the Actual Capacity Provided of Energy Efficiency measures being zero, as specified in Section III.13.7.2.2(c)(i)).

Reserve Requirement = the Ten-Minute Reserve Requirement during the interval.

Total Capacity Supply Obligation = the total amount of Capacity Supply Obligations in the New England Control Area during the interval, excluding the Capacity Supply Obligations associated with Energy Efficiency measures.

(c) If the Capacity Scarcity Condition is a result of a violation of the Zonal Reserve Requirement such that the associated Reserve Constraint Penalty Factor pricing applies, then the terms used in the formula above shall be calculated as follows:

Load = the total amount of Actual Capacity Provided (excluding applicable Real-Time Reserve Designations) from all resources in the Capacity Zone during the interval plus the net amount of energy imported into the Capacity Zone from outside the New England Control Area during the interval (but not less than zero) (with the Actual Capacity Provided of Energy Efficiency measures being zero, as specified in Section III.13.7.2.2(c)(i)).

Reserve Requirement = the Zonal Reserve Requirement minus any reserve support coming into the Capacity Zone over the internal transmission interface.

Total Capacity Supply Obligation = the total amount of Capacity Supply Obligations in the Capacity Zone during the interval, excluding the Capacity Supply Obligations associated with Energy Efficiency measures.

(d) The following provisions shall be used to determine the applicable Capacity Balancing Ratio where more than one of the conditions described in subsections (a), (b), and (c) apply in a Capacity Zone.

- (i) In any Capacity Zone subject to Reserve Constraint Penalty Factor pricing associated with both the Minimum Total Reserve Requirement and the Ten-Minute Reserve Requirement, but not the Zonal Reserve Requirement, the Capacity Balancing Ratio shall be calculated as described in Section III.13.7.2.3(a) for resources in that Capacity Zone.
- (ii) In any Capacity Zone subject to Reserve Constraint Penalty Factor pricing associated with both the Ten-Minute Reserve Requirement and the Zonal Reserve Requirement, but not the Minimum Total Reserve Requirement, the Capacity Balancing Ratio for resources in that Capacity Zone shall be the higher of the Capacity Balancing Ratio calculated as described in Section III.13.7.2.3(b) and the Capacity Balancing Ratio calculated as described in Section III.13.7.2.3(c).
- (iii) In any Capacity Zone subject to Reserve Constraint Penalty Factor pricing associated with the Minimum Total Reserve Requirement and the Zonal Reserve Requirement (regardless of whether the Capacity Zone is also subject to Reserve Constraint Penalty Factor pricing associated with the Ten-Minute Reserve Requirement), the Capacity Balancing Ratio for resources in that Capacity Zone shall be the higher of the Capacity Balancing Ratio calculated as described in Section III.13.7.2.3(a) and the Capacity Balancing Ratio calculated as described in Section III.13.7.2.3(c).

III.13.7.2.4 Capacity Performance Score.

Each resource, whether or not it has a Capacity Supply Obligation, will be assigned a Capacity Performance Score for each five-minute interval in which a Capacity Scarcity Condition exists in the Capacity Zone in which the resource is located. A resource's Capacity Performance Score for the interval shall equal the resource's Actual Capacity Provided during the interval (with the Actual Capacity Provided of Energy Efficiency measures being zero, as specified in Section III.13.7.2.2(c)(i)) minus the product of the resource's Capacity Supply Obligation (which for this purpose shall not be less than zero) and the applicable Capacity Balancing Ratio; provided, however, that for an On-Peak Demand Resource or a Seasonal Peak Demand Resource, the Capacity Supply Obligation associated with any Energy Efficiency measures shall be excluded from the calculation of the resource's Capacity Performance Score. The resulting Capacity Performance Score may be positive, zero, or negative.

III.13.7.2.5 Capacity Performance Payment Rate.

product of the applicable Capacity Clearing Price (indexed for inflation) multiplied by the resource's Capacity Supply Obligation for the Obligation Month).

III.13.7.3.2 Annual Stop-Loss.

(a) For each Obligation Month, the ISO shall calculate a stop-loss amount equal to:

$$\text{MaxCSO} \times [3 \text{ months} \times (\text{FCACP} - \text{FCASP}) - (12 \text{ months} \times \text{FCACP})]$$

Where:

MaxCSO = the resource's highest monthly Capacity Supply Obligation in the Capacity Commitment Period to date.

FCACP = the Capacity Clearing Price for the relevant Forward Capacity Auction.

FCASP = the Forward Capacity Auction Starting Price for the relevant Forward Capacity Auction.

(b) For each Obligation Month, the ISO shall calculate each resource's cumulative Capacity Performance Payments as the sum of the resource's Capacity Performance Payments for all months in the Capacity Commitment Period to date, with those monthly amounts limited as described in Section III.13.7.3.1.

(c) If the sum of the resource's Capacity Performance Payments (excluding any Capacity Performance Payments associated with Actual Capacity Provided above the resource's Capacity Supply Obligation in any interval) for all five-minute intervals in the Obligation Month is negative, the amount subtracted from the resource's Capacity Base Payment for the Obligation Month will be limited to an amount equal to the difference between the stop-loss amount calculated as described in Section III.13.7.3.2(a) and the resource's cumulative Capacity Performance Payments as described in Section III.13.7.3.2(b).

III.13.7.4 Allocation of Deficient or Excess Capacity Performance Payments.

For ~~each type of~~ Capacity Scarcity Conditions, as described in Section III.13.7.2.1 ~~and for each Capacity Zone~~, the ISO shall allocate deficient or excess Capacity Performance Payments as described in

subsections (a), ~~and (b), and (c)~~ below. ~~Where more than one type of Capacity Scarcity Condition applies, then the provisions below shall be applied in proportion to the duration of each type of Capacity Scarcity Condition.~~

(a) If the sum of all Capacity Performance Payments to all resources subject to ~~the a~~ Capacity Scarcity Condition ~~in the Capacity Zone~~ in an Obligation Month is positive, excluding any deficiency due to one or more resources reaching the stop-loss limit described in Section III.13.7.3, the deficiency ~~shall~~will be charged to resources in proportion to the sum of each such resource's Capacity Supply Obligation positive Capacity Performance Score for the Obligation Month, ~~excluding any resources subject to the stop-loss mechanism described in Section III.13.7.3 for the Obligation Month and excluding any resource, or portion thereof, consisting of Energy Efficiency measures. If the charge described in this Section III.13.7.4(a) causes a resource to reach the stop-loss limit described in Section III.13.7.3, then the stop-loss cap described in Section III.13.7.3 will be applied to that resource, and the remaining deficiency will be further allocated to other resources in the same manner as described in this Section III.13.7.4(a).~~

(b) If the sum of all Capacity Performance Payments to all resources subject to ~~the a~~ Capacity Scarcity Condition ~~in the Capacity Zone~~ in an Obligation Month is negative, excluding any deficiency due to one or more resources reaching the stop-loss limit described in Section III.13.7.3, the excess ~~will~~shall be credited to all such resources (excluding any resource, or portion thereof, consisting of Energy Efficiency measures) in proportion to each resource's Capacity Supply Obligation for the Obligation Month. For a resource subject to the stop-loss mechanism described in Section III.13.7.3 for the Obligation Month, any such credit shall be reduced (though not to less than zero) by the amount not charged to the resource as a result of the application of the stop-loss mechanism described in Section III.13.7.3, and the remaining excess ~~will~~shall be further allocated to other resources in the same manner as described in this Section III.13.7.4(b).

(c) If a deficiency of Capacity Performance Payments exists due to one or more resources reaching the stop-loss limit described in Section III.13.7.3, the deficiency shall be charged to all resources subject to a Capacity Scarcity Condition in an Obligation Month that have not reached their stop-loss limit (excluding any resource, or portion thereof, consisting of Energy Efficiency measures) in proportion to each resource's Capacity Supply Obligation for the Obligation Month. If the charge described in Section III.13.7.4(a) or the charge described in this Section III.13.7.4(c) causes a resource to reach the stop-loss limit described in Section III.13.7.3, then the stop-loss limit described in Section III.13.7.3 will be applied

[to that resource, and the remaining deficiency will be further allocated to other resources in the same manner as described in this Section III.13.7.4\(c\).](#)

III.13.7.5. Charges to Market Participants with Capacity Load Obligations.

III.13.7.5.1. Calculation of Capacity Charges Prior to June 1, 2022.

The provisions in this subsection apply to charges associated with Capacity Commitment Periods beginning prior to June 1, 2022. A load serving entity with a Capacity Load Obligation as of the end of the Obligation Month shall be subject to a charge equal to the product of: (a) its Capacity Load Obligation in the Capacity Zone; and (b) the applicable Net Regional Clearing Price. The Net Regional Clearing Price is defined as the sum of the total payments as defined in Section III.13.7 paid to resources with Capacity Supply Obligations in the Capacity Zone (excluding any capacity payments and charges made for Capacity Supply Obligation Bilaterals and excluding any Capacity Performance Payments), and including any applicable export charges or credits as determined pursuant to Section III.13.7.1.3 divided by the sum of all Capacity Supply Obligations (excluding (i) the quantity of capacity subject to Capacity Supply Obligation Bilaterals and (ii) the quantity of capacity clearing as Self-Supplied FCA Resources) assumed by resources in the zone. A load serving entity with a Capacity Load Obligation as of the end of the Obligation Month may also receive a failure to cover credit equal to the product of: (a) its Capacity Load Obligation in the Capacity Zone, and; (b) the sum of all failure to cover charges in the Capacity Zone calculated pursuant to Section III.13.3.4(b), divided by total Capacity Load Obligation in the Capacity Zone.

III.13.7.5.1.1. Calculation of Capacity Charges On and After June 1, 2022.

The provisions in this subsection apply to charges associated with Capacity Commitment Periods beginning on or after June 1, 2022. For purposes of this Section III.13.7.5.1.1, Capacity Zone costs calculated for a Capacity Zone that contains a nested Capacity Zone shall exclude the Capacity Zone costs of the nested Capacity Zone. A Market Participant with a Capacity Load Obligation on any day of the Obligation Month shall be subject to the following charges and adjustments. Each charge and adjustment described in subsection (b) of Sections III.13.7.5.1.1.1 through III.13.7.5.1.1.9 will be divided by the number of days in the month to derive a daily settlement value.

III.13.7.5.1.1.1 Forward Capacity Auction Charge.

The FCA charge, for each Capacity Zone, is: (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) Capacity Zone FCA Costs divided by Zonal Capacity Obligation.

III.15.6. Bilateral Capacity Contracts.

Market Participants shall be permitted to enter into Capacity Supply Obligation Bilaterals; ~~and Capacity Load Obligation Bilaterals; and Capacity Performance Bilaterals~~ in accordance with this Section III.15.6, with the ISO serving as Counterparty in each such transaction. Market Participants may not offset a Capacity Load Obligation with a Capacity Supply Obligation. To the extent necessary for the ISO's review and approval of any of the bilateral contracts described in this Section III.15.6, the ISO shall apply the Capacity Zones and external interfaces modeled as inputs and constraints in the Annual Capacity Auction for the applicable Capacity Commitment Period, as described in Section III.15.4.2.2. Resources with capacity subject to delayed deactivation pursuant to Sections II.52 and II.53 may not participate in Capacity Supply Obligation Bilaterals ~~or Capacity Performance Bilaterals~~, unless otherwise authorized pursuant to the terms of a cost-of-service agreement of the type described in Section II.54.1.

III.15.6.1. Capacity Supply Obligation Bilaterals.

A Capacity Transferring Resource having a Capacity Supply Obligation and seeking to shed that obligation may enter into a Capacity Supply Obligation Bilateral transaction to transfer its Capacity Supply Obligation, in whole or in part, to a Capacity Acquiring Resource, or portion thereof, for a whole-month period during the Capacity Commitment Period, as described in this Section III.15.6.1.

III.15.6.1.1. Terms of and Participation in Capacity Supply Obligation Bilaterals.

- (a) Capacity Supply Obligation Bilaterals are available for monthly periods, and a Capacity Supply Obligation Bilateral must be coterminous with a calendar month.
- (b) The qualification of Capacity Acquiring Resources for participation in Capacity Supply Obligation Bilaterals is determined in the same manner as the qualification of resources submitting supply offers for Monthly Reconfiguration Auctions as specified in Section III.15.5.2.1(b). A resource that does not have a Monthly Qualified Capacity value established for the month covered by the Capacity Supply Obligation Bilateral may not submit a transaction as a Capacity Acquiring Resource for that month.
- (c) A Capacity Supply Obligation Bilateral may not transfer a Capacity Supply Obligation amount that is greater than the monthly Capacity Supply Obligation of the Capacity Transferring Resource. A Capacity Supply Obligation Bilateral may not transfer a Capacity Supply Obligation amount that is greater than the amount of unobligated Monthly Qualified Capacity of the Capacity Acquiring Resource for the month covered by the Capacity Supply Obligation Bilateral. For the purpose of this subsection (c), unobligated Monthly Qualified Capacity refers to the Monthly Qualified Capacity that was

and the Capacity Load Obligation Acquiring Participant; and (iv) the Capacity Zone in which the Capacity Load Obligation is being transferred is located.

III.15.6.2.4. ISO Review.

The ISO shall review the information provided in support of the Capacity Load Obligation Bilateral and shall reject the Capacity Load Obligation Bilateral if any of the provisions of this Section III.15.6.2 are not met.

III.15.6.2.5. Approval.

Upon approval of a Capacity Load Obligation Bilateral, the Capacity Load Obligation of the Capacity Load Obligation Transferring Participant in the Capacity Zone specified in the submission to the ISO shall be reduced by the amount set forth in the Capacity Load Obligation Bilateral for the period covered by the bilateral and the Capacity Load Obligation of the Capacity Load Obligation Acquiring Participant in the specified Capacity Zone shall be increased by the amount set forth in the Capacity Load Obligation Bilateral for the period covered by the bilateral.

~~III.15.6.3. Capacity Performance Bilaterals.~~

~~A resource's Capacity Performance Score during a Capacity Scarcity Condition may be adjusted by entering into a Capacity Performance Bilateral as described in this Section III.15.6.3.~~

~~III.15.6.3.1. Terms of and Participation in Capacity Performance Bilaterals.~~

~~If a resource has a Capacity Performance Score that is greater than zero in a five minute interval that is subject to a Capacity Scarcity Condition, that resource may transfer all or some of that Capacity Performance Score to another resource for that same five minute interval through a Capacity Performance Bilateral, so long as both resources were subject to the same Capacity Scarcity Condition. The Lead Market Participant for the transferring resource may submit a Capacity Performance Bilateral to the ISO assigning all or a portion of its Capacity Performance Score for such five minute interval to the receiving resource. The Capacity Performance Bilateral must be confirmed by the Lead Market Participant for the resource receiving the Capacity Performance Score.~~

~~III.15.6.3.2. Timing of Submission to the ISO.~~

~~A Capacity Performance Bilateral must be submitted in accordance with resettlement provisions as described in ISO New England Manuals. However, to be included in the initial settlement of payments and charges associated with the Annual Capacity Market for the month associated with the Capacity~~

~~Performance Bilateral, a Capacity Performance Bilateral must be submitted to the ISO no later than 12:00 p.m. on the second Business Day after the end of that month, or at such later deadline as specified by the ISO upon notice to Market Participants (though a Capacity Performance Bilateral may be revised by the parties to the transaction throughout the resettlement process).~~

~~III.15.6.3.3. ————— Contents of Submission to the ISO.~~

~~The submission of a Capacity Performance Bilateral to the ISO shall include the following: (i) the resource identification number for the resource transferring its Capacity Performance Score; (ii) the resource identification number for the resource receiving the Capacity Performance Score; (iii) the MW amount of Capacity Performance Score being transferred; and (iv) the specific five minute interval or intervals for which the Capacity Performance Bilateral applies.~~

~~III.15.6.3.4. ————— ISO Review.~~

~~The ISO shall review the information provided in the submission of the Capacity Performance Bilateral and shall reject the Capacity Performance Bilateral if any of the provisions of this Section III.15.6.3 are not met.~~

~~III.15.6.3.5. ————— Effect of Capacity Performance Bilateral.~~

~~A Capacity Performance Bilateral does not affect either party's Capacity Supply Obligation or the rights and obligations associated therewith. The sole effect of a Capacity Performance Bilateral is to modify the Capacity Performance Scores of the transferring and receiving resources for the Capacity Scarcity Condition subject to the Capacity Performance Bilateral for purposes of calculating Capacity Performance Payments as described in Section III.15.8.2.~~

III.15.8. Capacity Payments and Charges.

Revenue in the Annual Capacity Market for resources providing capacity shall be composed of Capacity Base Payments as described in Section III.15.8.1 and Capacity Performance Payments as described in Section III.15.8.2, adjusted as described in Section III.15.8.3 and Section III.15.8.4. Market Participants with a Capacity Load Obligation shall be subject to charges as described in Section III.15.8.5.

In the event of a change in the Lead Market Participant for a resource that has a Capacity Supply Obligation, the Capacity Supply Obligation shall remain associated with the resource and the new Lead Market Participant for the resource shall be bound by all provisions of this Section III.15 arising from such Capacity Supply Obligation. The Lead Market Participant for the resource at the start of an Obligation Month shall be responsible for all payments and charges associated with that resource in that Obligation Month.

III.15.8.1. Capacity Base Payments.

Resources acquiring or shedding a Capacity Supply Obligation for the Obligation Month shall receive a Capacity Base Payment for the Obligation Month reflecting the payments and charges described in Section III.15.8.1.1.

III.15.8.1.1. Payments and Charges Reflecting Capacity Supply Obligations.

Each resource that has: (i) cleared in an Annual Capacity Auction, except for the portion of resources designated as Self-Supplied Capacity Resources; (ii) cleared in a reconfiguration auction; or (iii) entered into a Capacity Supply Obligation Bilateral shall be entitled to a monthly payment or charge during the Capacity Commitment Period. Each monthly payment and charge listed in Section III.15.8.1.1 (a) through (d) below will be divided by the number of days in the month to derive a daily settlement value.

(a) **Annual Capacity Auction.** For a resource whose offer has cleared in an Annual Capacity Auction, the monthly capacity payment shall equal the product of its cleared capacity and the Capacity Clearing Price in the Capacity Zone in which the resource is located as adjusted by applicable indexing for resources with additional Capacity Commitment Period elections pursuant to Section III.13.1.1.2.2.4 in the manner described below. For a resource that elected to have the Capacity Clearing Price and the Capacity Supply Obligation apply for more than one Capacity Commitment Period, payments associated with the Capacity Supply Obligation and Capacity Clearing Price (indexed using the Handy-Whitman Index of Public Utility Construction Costs in effect as of December 31 of the year preceding the Capacity Commitment Period) shall continue to apply after the Capacity Commitment Period associated with the

Baseline of the Demand Response Asset or Distributed Energy Resource associated with the Demand Response Distributed Energy Resource Aggregation; and (3) the resulting MWhs of reduction, other than the MWhs associated with Net Supply, shall be increased by average avoided peak transmission and distribution losses.

III.15.8.2.3. Capacity Balancing Ratio.

For each five-minute interval in which a Capacity Scarcity Condition exists, the ISO shall calculate a Capacity Balancing Ratio using the following formula:

$$(\text{Load} + \text{Reserve Requirement}) / \text{Total Capacity Supply Obligation}$$

provided, however, that the Capacity Balancing Ratio shall not exceed a value of 1.0.

(a) If the Capacity Scarcity Condition is a result of a violation of the Minimum Total Reserve Requirement such that the associated system-wide Reserve Constraint Penalty Factor pricing applies, then the terms used in the formula above shall be calculated as follows:

Load = the total amount of Actual Capacity Provided (excluding applicable Real-Time Reserve Designations) from all resources in the New England Control Area during the interval (with the Actual Capacity Provided of Energy Efficiency measures being zero, as specified in Section III.15.8.2.2(c)(i)).

Reserve Requirement = the Minimum Total Reserve Requirement during the interval.

Total Capacity Supply Obligation = the total amount of Capacity Supply Obligations in the New England Control Area during the interval, excluding the Capacity Supply Obligations associated with Energy Efficiency measures.

(b) If the Capacity Scarcity Condition is a result of a violation of the Ten-Minute Reserve Requirement such that the associated system-wide Reserve Constraint Penalty Factor pricing applies, then the terms used in the formula above shall be calculated as follows:

Load = the total amount of Actual Capacity Provided (excluding applicable Real-Time Reserve Designations) from all resources in the New England Control Area during the interval (with the Actual Capacity Provided of Energy Efficiency measures being zero, as specified in Section III.15.8.2.2(c)(i)).

Reserve Requirement = the Ten-Minute Reserve Requirement during the interval.

Total Capacity Supply Obligation = the total amount of Capacity Supply Obligations in the New England Control Area during the interval, excluding the Capacity Supply Obligations associated with Energy Efficiency measures.

(c) If the Capacity Scarcity Condition is a result of a violation of the Zonal Reserve Requirement such that the associated Reserve Constraint Penalty Factor pricing applies, then the terms used in the formula above shall be calculated as follows:

Load = the total amount of Actual Capacity Provided (excluding applicable Real-Time Reserve Designations) from all resources in the Capacity Zone during the interval plus the net amount of energy imported into the Capacity Zone from outside the New England Control Area during the interval (but not less than zero) (with the Actual Capacity Provided of Energy Efficiency measures being zero, as specified in Section III.15.8.2.2(c)(i)).

Reserve Requirement = the Zonal Reserve Requirement minus any reserve support coming into the Capacity Zone over the internal transmission interface.

Total Capacity Supply Obligation = the total amount of Capacity Supply Obligations in the Capacity Zone during the interval, excluding the Capacity Supply Obligations associated with Energy Efficiency measures.

(d) The following provisions shall be used to determine the applicable Capacity Balancing Ratio where more than one of the conditions described in subsections (a), (b), and (c) apply in a Capacity Zone.

(i) In any Capacity Zone subject to Reserve Constraint Penalty Factor pricing associated with both the Minimum Total Reserve Requirement and the Ten-Minute Reserve Requirement, but not the Zonal Reserve Requirement, the Capacity Balancing Ratio shall be calculated as described in Section III.15.8.2.3(a) for resources in that Capacity Zone.

(ii) In any Capacity Zone subject to Reserve Constraint Penalty Factor pricing associated with both the Ten-Minute Reserve Requirement and the Zonal Reserve Requirement, but not the

Minimum Total Reserve Requirement, the Capacity Balancing Ratio for resources in that Capacity Zone shall be the higher of the Capacity Balancing Ratio calculated as described in Section III.15.8.2.3(b) and the Capacity Balancing Ratio calculated as described in Section III.15.8.2.3(c).

(iii) In any Capacity Zone subject to Reserve Constraint Penalty Factor pricing associated with the Minimum Total Reserve Requirement and the Zonal Reserve Requirement (regardless of whether the Capacity Zone is also subject to Reserve Constraint Penalty Factor pricing associated with the Ten-Minute Reserve Requirement), the Capacity Balancing Ratio for resources in that Capacity Zone shall be the higher of the Capacity Balancing Ratio calculated as described in Section III.15.8.2.3(a) and the Capacity Balancing Ratio calculated as described in Section III.15.8.2.3(c).

III.15.8.2.4. Capacity Performance Score.

Each resource, whether or not it has a Capacity Supply Obligation, will be assigned a Capacity Performance Score for each five-minute interval in which a Capacity Scarcity Condition exists in the Capacity Zone in which the resource is located. A resource's Capacity Performance Score for the interval shall equal the resource's Actual Capacity Provided during the interval (with the Actual Capacity Provided of Energy Efficiency measures being zero, as specified in Section III.15.8.2.2(c)(i)) minus the product of the resource's Capacity Supply Obligation (which for this purpose shall not be less than zero) and the applicable Capacity Balancing Ratio; provided, however, that for an On-Peak Demand Capacity Resource or a Seasonal Peak Demand Capacity Resource, the Capacity Supply Obligation associated with any Energy Efficiency measures shall be excluded from the calculation of the resource's Capacity Performance Score. The resulting Capacity Performance Score may be positive, zero, or negative.

III.15.8.2.5. Capacity Performance Payment Rate.

The Capacity Performance Payment Rate shall be \$9337/MWh. The ISO shall review the Capacity Performance Payment Rate in the stakeholder process as needed and shall file with the Commission a new Capacity Performance Payment Rate if and as appropriate.

III.15.8.2.6. Calculation of Capacity Performance Payments.

For each resource, whether or not it has a Capacity Supply Obligation, the ISO shall calculate a Capacity Performance Payment for each five-minute interval in which a Capacity Scarcity Condition exists in the Capacity Zone in which the resource is located. A resource's Capacity Performance Payment for an

(b) For each Obligation Month, the ISO shall calculate each resource's cumulative Capacity Performance Payments as the sum of the resource's Capacity Performance Payments for all months in the Capacity Commitment Period to date, with those monthly amounts limited as described in Section III.15.8.3.1.

(c) If the sum of the resource's Capacity Performance Payments (excluding any Capacity Performance Payments associated with Actual Capacity Provided above the resource's Capacity Supply Obligation in any interval) for all five-minute intervals in the Obligation Month is negative, the amount subtracted from the resource's Capacity Base Payment for the Obligation Month shall be limited to an amount equal to the difference between the stop-loss amount calculated as described in Section III.15.8.3.2(a) and the resource's cumulative Capacity Performance Payments as described in Section III.15.8.3.2(b).

III.15.8.4. Allocation of Deficient or Excess Capacity Performance Payments.

For ~~each type of~~ Capacity Scarcity Condition~~s~~ as described in Section III.15.8.2.1 ~~and for each Capacity Zone~~, the ISO shall allocate deficient or excess Capacity Performance Payments as described in subsections (a), ~~and (b), and (c)~~ below. ~~Where more than one type of Capacity Scarcity Condition applies, then the provisions below shall be applied in proportion to the duration of each type of Capacity Scarcity Condition.~~

(a) If the sum of all Capacity Performance Payments to all resources subject to ~~the a~~ Capacity Scarcity Condition ~~in the Capacity Zone~~ in an Obligation Month is positive, ~~excluding any deficiency due to one or more resources reaching the stop-loss limit described in Section III.15.8.3~~, the deficiency ~~will~~ shall be charged to resources in proportion to ~~the sum of~~ each such resource's ~~Capacity Supply Obligation~~ positive Capacity Performance Score for the Obligation Month, ~~excluding any resources subject to the stop-loss mechanism described in Section III.15.8.3 for the Obligation Month and excluding any resource, or portion thereof, consisting of Energy Efficiency measures. If the charge described in this Section III.15.8.4(a) causes a resource to reach the stop-loss limit described in Section III.15.8.3, then the stop-loss cap described in Section III.15.8.3 will be applied to that resource, and the remaining deficiency will be further allocated to other resources in the same manner as described in this Section III.15.8.4(a).~~

(b) If the sum of all Capacity Performance Payments to all resources subject to ~~the a~~ Capacity Scarcity Condition ~~in the Capacity Zone~~ in an Obligation Month is negative, ~~excluding any deficiency due to one or more resources reaching the stop-loss limit described in Section III.15.8.3~~, the excess ~~will~~

shall be credited to all such resources (excluding any resource, or portion thereof, consisting of Energy Efficiency measures) in proportion to each resource's Capacity Supply Obligation for the Obligation Month. For a resource subject to the stop-loss mechanism described in Section III.15.8.3 for the Obligation Month, any such credit shall be reduced (though not to less than zero) by the amount not charged to the resource as a result of the application of the stop-loss mechanism described in Section III.15.8.3, and the remaining excess ~~will~~ shall be further allocated to other resources in the same manner as described in this Section III.15.8.4(b).

(c) If a deficiency of Capacity Performance Payments exists due to one or more resources reaching the stop-loss limit described in Section III.15.8.3, the deficiency shall be charged to all resources subject to a Capacity Scarcity Condition in an Obligation Month that have not reached their stop-loss limit (excluding any resource, or portion thereof, consisting of Energy Efficiency measures) in proportion to each resource's Capacity Supply Obligation for the Obligation Month. If the charge described in Section III.15.8.4(a) or the charge described in this Section III.15.8.4(c) causes a resource to reach the stop-loss limit described in Section III.15.8.3, then the stop-loss limit described in Section III.15.8.3 will be applied to that resource, and the remaining deficiency will be further allocated to other resources in the same manner as described in this Section III.15.8.4(c).

III.15.8.5. Charges to Market Participants with Capacity Load Obligations.

III.15.8.5.1. Calculation of Capacity Charges.

For purposes of this Section III.15.8.5.1, Capacity Zone costs calculated for a Capacity Zone that contains a nested Capacity Zone shall exclude the Capacity Zone costs of the nested Capacity Zone. A Market Participant with a Capacity Load Obligation on any day of the Obligation Month shall be subject to the following charges and adjustments. Each charge and adjustment described in rate component (b) of Sections III.15.8.5.1.1 through III.15.8.5.1.8 shall be divided by the number of days in the month to derive a daily settlement value.

III.15.8.5.1.1. Annual Capacity Auction Charge.

The ACA charge, for each Capacity Zone, is: (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) Capacity Zone ACA Costs divided by Zonal Capacity Obligation.

Where:

EXHIBIT IA

ISO NEW ENGLAND FINANCIAL ASSURANCE POLICY

Table of Contents

Overview

- I. GROUPS REGARDED AS SINGLE MARKET PARTICIPANTS
- II. MARKET PARTICIPANTS' REVIEW AND CREDIT LIMITS
 - A. Minimum Criteria for Market Participation
 - 1. Information Disclosure
 - 2. Risk Management
 - 3. Communications
 - 4. Capitalization
 - 5. Additional Eligibility Requirements
 - 6. Prior Uncured Defaults
 - B. Proof of Financial Viability for Applicants
 - C. Ongoing Review and Credit Ratings
 - 1. Rated and Credit Qualifying Market Participants
 - 2. Unrated Market Participants
 - 3. Information Reporting Requirements for Market Participants
 - D. Market Credit Limits
 - 1. Market Credit Limit for Non-Municipal Market Participants
 - a. Market Credit Limit for Rated Non-Municipal Market Participants
 - b. Market Credit Limit for Unrated Non-Municipal Market Participants
 - 2. Market Credit Limit for Municipal Market Participants
 - E. Transmission Credit Limits
 - 1. Transmission Credit Limit for Rated Non-Municipal Market Participants
 - 2. Transmission Credit Limit for Unrated Non-Municipal Market Participants
 - 3. Transmission Credit Limit for Municipal Market Participants
 - F. Credit Limits for FTR-Only Customers
 - G. Total Credit Limit
- III. MARKET PARTICIPANTS' REQUIREMENTS
 - A. Determination of Financial Assurance Obligations

Designated FTR Participant the balance of such financial assurance after all such overdue obligations have been satisfied.

VII. ADDITIONAL PROVISIONS FOR FORWARD CAPACITY MARKETS

Any Lead Market Participant, including any Provisional Member that is a Lead Market Participant, transacting in the Forward Capacity Market that is otherwise required to provide additional financial assurance under the ISO New England Financial Assurance Policy (each a “Designated FCM Participant”), is required to provide additional financial assurance meeting the requirements of Section X below in the amounts described in this Section VII (such amounts being referred to in the ISO New England Financial Assurance Policy as the “FCM Financial Assurance Requirements”). If the Lead Market Participant for a Resource changes, then the new Lead Market Participant for the Resource shall become the Designated FCM Participant.

A. FCM Delivery Financial Assurance

Each Designated FCM Participant that has a Capacity Supply Obligation for the Capacity Commitment Period associated with the sixteenth Forward Capacity Auction or any Capacity Commitment Period thereafter, shall be subject to a “Corporate Liquidity Assessment” as described in this Section VII.A to determine its FCM Delivery Financial Assurance.

1. FCM Delivery Financial Assurance Calculation

A Designated FCM Participant must include, for the Capacity Supply Obligation of each resource in its portfolio other than the Capacity Supply Obligation associated with any Energy Efficiency measures, FCM Delivery Financial Assurance in the calculation of its FCM Financial Assurance Requirements under the ISO New England Financial Assurance Policy. If a Designated FCM Participant’s FCM Delivery Financial Assurance is negative, it will be used to reduce the Designated FCM Participant’s Financial Assurance Obligations (excluding FTR Financial Assurance Requirements), but not to less than zero.

FCM Delivery Financial Assurance is calculated according to the following formula for a Designated FCM Participant that has a Capacity Supply Obligation up to and including the end of the Capacity Commitment Period associated with the fifteenth Forward Capacity Auction:

FCM Delivery Financial Assurance = $[DFAMW \times PE \times \max[(ABR - CWAP), 0.1] \times SF]$
– IMC – MCC

FCM Delivery Financial Assurance is calculated according to the following applicable formula for a Designated FCM Participant that has a Capacity Supply Obligation commencing at the beginning of the Capacity Commitment Period associated with the sixteenth Forward Capacity Auction and every Capacity Commitment Period thereafter. The applicable FCM Delivery Financial Assurance formula is determined by the results of a Corporate Liquidity Assessment and is limited by the operation of the applicable stop-loss mechanisms as set forth in Market Rule 1 (including those that may apply in the next Capacity Commitment Period).

Corporate Liquidity Assessment Result: Low Risk

FCM Delivery Financial Assurance = $[DFAMW \times PE \times \max[(ABR - CWAP), 0.1] \times SF]$ – IMC – MCC

Corporate Liquidity Assessment Result: Medium Risk

FCM Delivery Financial Assurance = $[DFAMW \times PE \times \max[(ABR - CWAP), 0.1] \times SF]$ – IMC – MCC – Peak Monthly Stop-loss $\times \max[(ABR - CWAP), 0.1]$

Corporate Liquidity Assessment Result: High Risk

FCM Delivery Financial Assurance = $[DFAMW \times PE \times \max[(ABR - CWAP), 0.1] \times SF]$ – IMC – MCC – Peak Monthly Stop-loss $\times \max[(ABR - CWAP), 0.1]$
– Second Largest Monthly Stop-loss $\times \max[(ABR - CWAP), 0.1]$

Where:

MCC (monthly capacity charge) equals monthly capacity payments incurred in previous months, which have not yet been invoiced in instances where the MCC is a credit to the Designated FCM Participant or have not yet been invoiced and paid in instances where the MCC is a charge to the Designated FCM Participant. The MCC is estimated from the first day of the current delivery month until it is replaced by the actual settled MCC value when settlement is complete.

IMC (intra-month collateral) equals estimated monthly capacity payments incurred during the current delivery month as limited by the difference (which shall in no event be less than zero) between (A) the minimum of the applicable monthly stop-loss and the remaining annual stop-loss as described in Section III.13.7.3.1 and Section III.13.7.3.2 of Market Rule 1, respectively, and (B) the amount of additional FCM Delivery Financial Assurance when considering the Designated FCM Participant's current month FCM Delivery Financial Assurance obligation as compared to the Designated FCM Participant's next month FCM Delivery Financial Assurance obligation, in each case without giving effect to the IMC and MCC variables when calculating such additional amount. Where the estimated monthly capacity payments for each Designated FCM Participant, shall be updated three (3) days after publication of the most recent FCM Preliminary Capacity Performance Score report (or equivalent report) on the Market Information Server.

DFAMW (delivery financial assurance MW) equals the sum of the Capacity Supply Obligations of each resource in the Designated FCM Participant's portfolio for the month, excluding the Capacity Supply Obligation of any resource that has reached the annual stop-loss as described in Section III.13.7.3.2 of Market Rule 1. If the calculated DFAMW is less than zero, then the DFAMW will be set equal to zero.

PE (potential exposure) is a monthly value calculated for the Designated FCM Participant's portfolio as the difference between the Capacity Supply Obligation weighted average Forward Capacity Auction Starting Price and the Capacity Supply Obligation weighted average capacity price for the portfolio, excluding the Capacity Supply Obligation of any resource that has reached the annual stop-loss as described in Section III.13.7.3.2 of Market Rule 1. The Forward Capacity Auction Starting Price shall correspond to that used in the Forward Capacity Auction corresponding to the current Capacity Commitment Period and the capacity prices shall correspond to those used in the calculation of the Capacity Base Payment for each Capacity Supply Obligation in the delivery month.

In the case of a resource subject to a multi-year Capacity Commitment Period election made in a Forward Capacity Auction prior to the ninth Forward Capacity Auction as described in Sections III.13.1.1.2.2.4 and III.13.1.4.1.1.2.7 of Market Rule 1, the Forward

Capacity Auction Starting Price shall be replaced with the applicable Capacity Clearing Price (indexed for inflation) in the above calculation until the multi-year election period expires.

ABR (average balancing ratio) is the duration-weighted average of all of the system-wide Capacity Balancing Ratios calculated for each system-wide Capacity Scarcity Condition occurring in the relevant group of months in the three Capacity Commitment Periods immediately preceding the current Capacity Commitment Period and those occurring in the months within the relevant group that are prior to the current month of the current Capacity Commitment Period, as the data becomes available. [For purposes of calculating the ABR, all Capacity Balancing Ratios, including Capacity Balancing Ratios for Capacity Scarcity Conditions that occurred in past Capacity Commitment Periods or in the months within the relevant group that are prior to the current month of the current Capacity Commitment Period, shall be calculated utilizing the Capacity Balancing Ratio formula that is currently effective, as described in Section III.13.7.2.3 or Section III.15.8.2.3 of Market Rule 1.](#) Three separate groups of months shall be used for this purpose: June through September, December through February, and all other months. Until data exists to calculate this number, the temporary ABR for June through September shall equal 0.90; the temporary ABR for December through February shall equal 0.70; and the temporary ABR for all other months shall equal 0.60.

CWAP (capacity weighted average performance) is the capacity weighted average performance of the Designated FCM Participant's portfolio. For each resource in the Designated FCM Participant's portfolio, excluding any resource that has reached the annual stop-loss as described in Section III.13.7.3.2 of Market Rule 1, and excluding from the remaining resources the resource having the largest Capacity Supply Obligation in the month, the resource's Capacity Supply Obligation shall be multiplied by the average performance of the resource. The CWAP shall be the sum of all such values, divided by the Designated FCM Participant's DFAMW. If the DFAMW is zero, then the CWAP is set equal to one.

The average performance of a resource is the Actual Capacity Provided during Capacity Scarcity Conditions divided by the product of the resource's Capacity Supply Obligation and the equivalent hours of Capacity Scarcity Conditions in the relevant group of months

in the three Capacity Commitment Periods immediately preceding the current Capacity Commitment Period and those occurring in the months within the relevant group that are prior to the current month of the current Capacity Commitment Period, as the data becomes available. Three separate groups of months shall be used for this purpose: June through September, December through February, and all other months. Until data exists to calculate this number, the temporary average performance for gas-fired steam generating resources, combined-cycle combustion turbines and simple-cycle combustion turbines shall equal 0.90; the temporary average performance for coal-fired steam generating resources shall equal 0.85; the temporary average performance for oil-fired steam generating resources shall equal 0.65; the temporary average performance for all other resources shall equal 1.00. The applicable temporary average performance value will be used for new and existing resources until actual performance data is available.

SF (scaling factor) is a month-specific multiplier, as follows:

June and December	2.000;
July and January	1.732;
August and February	1.414;
All other months	1.000.

Peak Monthly Stop-loss equals the largest monthly stop-loss for the Designated FCM Participant that would occur during the period from the current delivery month through the following five consecutive months, where each monthly stop-loss is equal to the sum of the monthly stop-losses of each resource in the Designated FCM Participant's portfolio as described in Section III.13.7.3.1 of Market Rule 1.

Second Largest Monthly Stop-loss equals the second largest monthly stop-loss for the Designated FCM Participant that would occur during the period from the current delivery month through the following five consecutive months, where each monthly stop-loss is equal to the sum of the monthly stop-losses of each resource in the Designated FCM Participant's portfolio as described in Section III.13.7.3.1 of Market Rule 1.

2. Corporate Liquidity Assessment Methodology

The ISO will perform a "Corporate Liquidity Assessment" to determine the appropriate liquidity risk assessment category for each Designated FCM Participant (i.e., low risk,



memo

To: NEPOOL Markets Committee

From: Megan Sweitzer, Lead Analyst

Date: May 6, 2026

Subject: Pay-for-Performance Revisions: Balancing Ratio Compliance (WMPP ID: 189)

The ISO is requesting a vote on proposed Tariff revisions to cap the Capacity Balancing Ratio at 1.0 and ensure capacity resources are not charged for a share-of-system obligation higher than their Capacity Supply Obligation (CSO) MW.

As a result of the New England Power Generators Association's complaint (EL25-106-000) the Federal Energy Regulatory Commission ordered the ISO to cap the Capacity Balancing Ratio at 1.0. This proposal enables the required balancing ratio capping and updates the Capacity Performance Payment allocations appropriately, with deficiencies being allocated proportionally by overperformance across the month and excess Capacity Performance Payments continuing to go to resources with a Capacity Supply Obligation (CSO) proportionally by CSO MW. In addition, to simplify implementation and remove an inefficiency, the ISO proposes to remove Capacity Performance Bilaterals, which have seldom been utilized.

The Markets Committee has reviewed the proposed changes highlighted above including the Market Rule 1 language and corresponding I.2.2 definitions. The proposal has been presented on the meeting dates outlined below:

- March 10-12, 2026, [agenda item #04](#)
- April 14-16, 2026 [agenda item #05](#)
- May 12-14, 2026, [agenda item #02](#)



Pay-for-Performance Revisions: Balancing Ratio Compliance

*Proposed PFP Revisions for Compliance with Order to
Cap the Capacity Balancing Ratio*

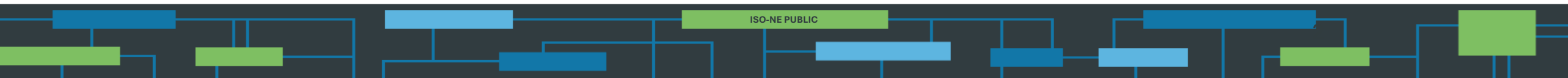
Megan Sweitzer & Enrico De Magistris

LEAD ANALYST & ECONOMIST



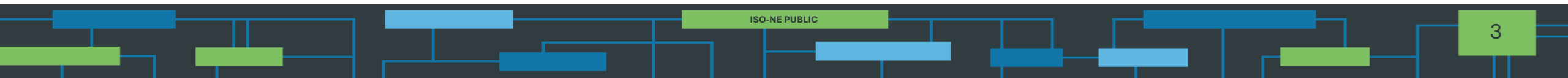
Proposed Effective Date: July 25, 2025

- On January 22, 2026, the Federal Energy Regulatory Commission (FERC, the Commission) issued an [order in Docket EL25-106](#) for ISO-NE to cap the Capacity Balancing Ratio (BR) at 1.0
- The order followed from NEPGA's July 2025 Section 206 filing about the Pay-for-Performance (PFP) design. FERC granted the complaint in part and denied in part:
 - Granted cap on Balancing Ratio (BR)
 - Denied with regard to the allocation methodology for the stop-loss mechanism
- Today's discussion reviews the requirements of the order and introduces the proposed changes:
 - In accordance with the order, ISO-NE will cap the Balancing Ratio at 1.0 and make necessary conforming changes
- A compliance filing is due by July 21, 2026, with a refund effective date of July 25, 2025



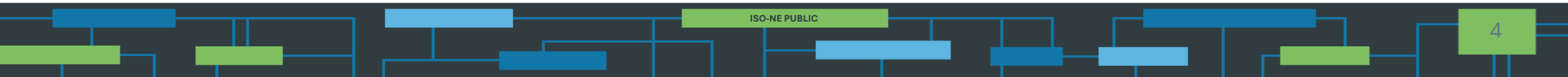
BACKGROUND, REQUIREMENTS, AND DESIGN PRINCIPLES

This section will provide background on the Balancing Ratio and Commission order



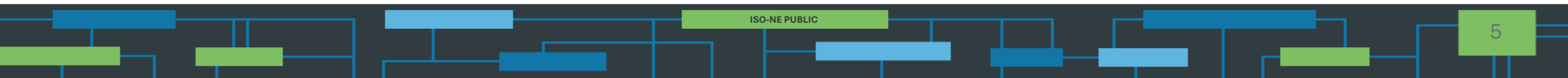
Background

- On June 24, 2025, the system's total load and reserve requirement exceeded the total Capacity Supply Obligation (CSO) of all capacity resources in the New England system during a Capacity Scarcity Condition (CSC) event
- These conditions caused the Balancing Ratio to surpass 1.0 for the first time during a CSC, averaging 1.031 over the 37 intervals of the event
 - The Balancing Ratio is the sum of load and the reserve requirement divided by the total system CSO and is used to determine a capacity resource's share-of-system obligation during a CSC
- When the Balancing Ratio exceeded 1.0, capacity resources were financially responsible for a share-of-system obligation higher than their CSO MW



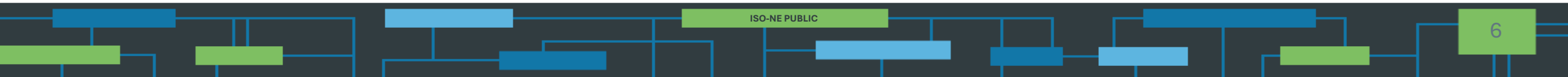
Requirements for Compliance with Order

- Cap the Capacity Balancing Ratio at 1.0
- Compliance filing includes conforming changes necessary to implement the Balancing Ratio cap
- Refund effective date is July 25, 2025, consistent with the complaint filing date
 - Scarcity conditions that occur prior to acceptance of the compliance filing would be subject to resettlement if the Balancing Ratio exceeds 1.0



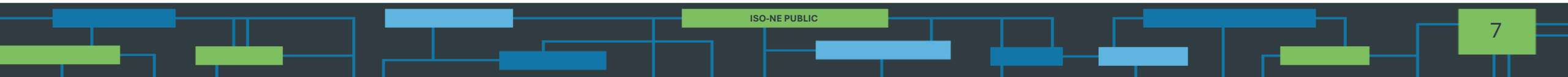
Design Objectives

- Preserve the PFP design when the Balancing Ratio is below 1.0
- Do not charge capacity resources for failing to perform beyond their CSO MW during scarcity conditions
- Continue to distribute excess Capacity Performance Payments (CPP) as a credit to CSO resources
- Keep the “effective” payment rate for overperformance as close to the Tariff-specified Performance Payment Rate (PPR) as possible



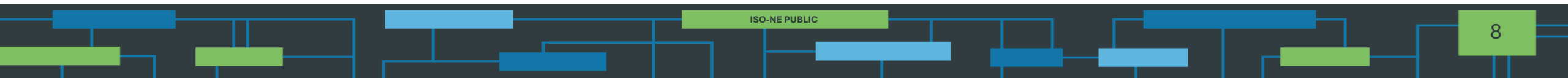
CAPPING THE CAPACITY BALANCING RATIO

How the ISO proposes to comply with the Commission Order to cap the Balancing Ratio and ensure capacity resources are not held to an obligation beyond their CSO MW



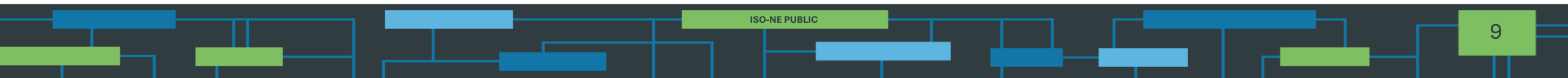
Overview of Proposed Changes

- Cap the Balancing Ratio at the lesser of 1.0 or
(Load + Reserve Requirement)/Total Capacity Supply Obligation
- Capping the Balancing Ratio impacts the balancing fund of CPP
 - Balancing fund = sum of all CPP (performance charges and performance credits)
 - Excess balancing fund = performance charges greater than performance credits
 - Deficient balancing fund = performance charges less than performance credits
- Currently, excess or deficient funds are credited or charged to CSO resources (pro-rata by CSO MW)
- To align with design principles, ISO-NE proposes to
 - Continue allocating an excess balancing fund (i.e., a net surplus) to CSO resources
 - Change the allocation of deficient balancing fund from CSO resources to overperformers
 - This change ensures resources performing at their CSO MW are not charged
 - This change lowers the “effective” PPR for overperformance when a deficiency exists



Stop Loss and Balancing Fund Allocations are Independent

- The allocation of stopped losses will be separated from the calculation and allocation of deficient or excess Capacity Performance Payments
- The balancing fund of deficient or excess Capacity Performance Payments is calculated as the sum of all Capacity Performance Payments to all resources subject to the CSC in the Obligation Month, excluding any deficiency due to stopped losses
- This separation is necessary because stopped losses will continue to be allocated pro-rata to CSO MW, consistent with the Commission's order
- A deficiency of CPP for other reasons (such as a capped Balancing Ratio) will be allocated to reduce payments for overperformance
 - Allocating a deficiency resulting from a capped BR to CSO resources would result in the same charges to CSO resources as an uncapped BR



ISO Proposes to Allocate Deficient CPP at a Monthly Level

- Payments for overperformance are reduced uniformly across the month (proportionally by MWh), regardless of which interval or CSC event the performance occurred
- Results in a single “effective” PPR for overperformance for the month, and ensures equal payments for equal performance within a month
- Aligns with the monthly allocation of excess CPP to CSO resources
- Deficient Capacity Performance Payments (excluding the allocation of stopped losses) reduce payments for positive performance (\$/MWh)
 - Deficiency Allocation_{resource, month} =

$$\text{Balancing Fund}_{\text{month}} \times (\text{Overperformance}_{\text{resource, month}} \text{ MWh} / \text{Overperformance}_{\text{total, month}} \text{ MWh})$$
 - Effective PPR for Overperformance =

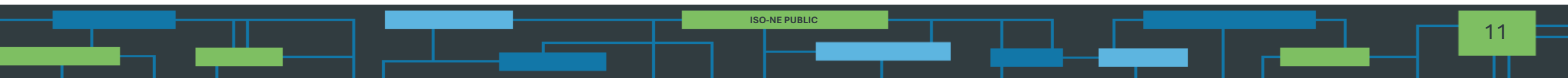
$$\min(\text{PPR}, \text{Negative Performance Payments}_{\text{month}} / \text{Overperformance}_{\text{month}} \text{ MWh})$$

Effects of Balancing Ratio Cap and Changes to Allocation During June 2025 CSC

- The table describes how the proposal changes would have shifted Capacity Performance Payments under similar conditions to the June 2025 CSC

Measure	Direction	Mechanism
Total Performance Charges	Lower	BR cap -> fewer negative scores -> lower charges
Total Performance Credits Owed at Full PPR	Higher	BR cap -> higher scores -> more credits owed
Balancing Fund of Excess/Deficient CPP	Lower	Lower charges + more credits -> lower net CPP fund
Stopped Losses	Lower	Lower charges -> fewer stopped losses accrue
Total Payments to CSO Resources	Higher	Lower charges + more credits + lower stop loss -> higher CPP
Total Payments for Overperformance/ Effective PPR	Lower	Fewer charges collected + more overperformance -> lower CPP and effective PPR

- Effective PPR for overperformance in June 2025 CSC under this proposal: about \$8,000/MWh
- Not all events with a capped Balancing Ratio will result in a lower effective PPR for overperformance (see example scenario 2 in the appendix)



Capped Balancing Ratio Example

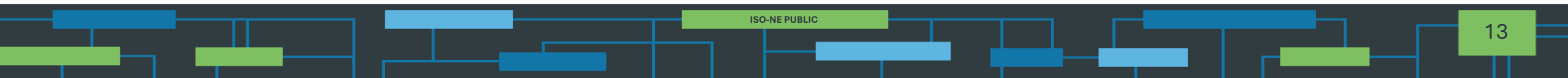
- There is more overperformance than underperformance with the BR capped at 1.0
- Fewer performance charges accrue from less underperformance
- More overperformance credits owed due to lower BR
- Fewer charges divided by higher positive performance results in an effective PPR of \$4,669
- CSO resources have higher CPP compared to an uncapped BR
- Overperformers have reduced CPP compared to an uncapped BR
- CPP for CSO resources with positive performance scores influenced by both dynamics

Case with Balancing Ratio Capped and PPR of \$9,337

	Load+RR = 3,120 MW 1-hour CSC	Unit	Res 1	Res 2	Res 3	System
1	Balancing Ratio (1.04 capped at 1.0)	Num	1.0	1.0	1.0	1.0
2	Capacity Supply Obligation	MW	0	1,000	2,000	3,000
3	Actual Capacity Provided	MW	100	900	2,100	3,100
4	Capacity Performance Score (BR Uncapped)	Num	100	-140	20	-20
5	Capacity Performance Score (BR Capped)	Num	100	-100	100	100
6	Capacity Performance Payment + Excess (BR Uncapped)	\$	933,700	-1,244,933	311,233	0
7	Capacity Performance Payment + Deficiency (BR Capped)	\$	466,850	-933,700	466,850	0
8	Difference in Final Capacity Performance Payment	\$	-466,850	311,233	155,617	0

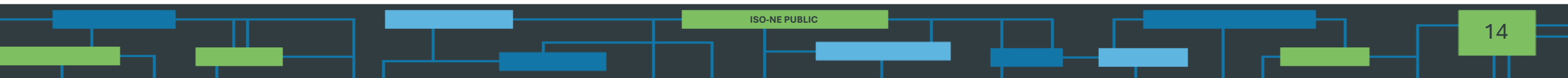
CONFORMING CHANGES

Conforming changes to Capacity Performance Bilaterals, mitigation, and capacity zones



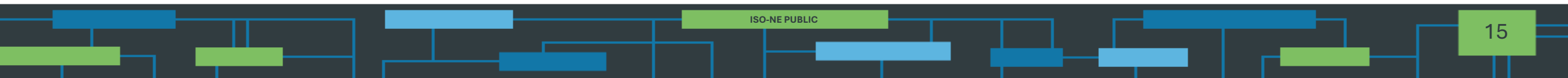
Capacity Performance Bilaterals

- Capacity Performance Bilaterals are one of several tools for capacity suppliers to manage potential non-performance risk
- Under current rules, a capacity resource with a positive Capacity Performance Score in a 5-minute interval can transfer some or all of that score to another resource subject to the same CSC
- In theory, Capacity Performance Bilaterals could be used as a risk-hedging tool prior to a CSC occurring
 - For example, a resource on a maintenance outage may use a Performance Bilateral to hedge against the possibility of performance charges during a CSC while out of service
 - Little financial incentive to engage in bilateral trades between participants after a CSC since positive and negative scores have equal monetary value under current rules
- Allows resources to reduce their financial exposure over shorter time periods or on shorter notice than other options



Proposal Removes Mechanism for Capacity Performance Bilaterals

- Asymmetric trade values between positive and negative performance scores can lead to a “money-for-nothing” problem and further reductions to the effective PPR
 - A positive score may have a lower effective payment value ($< \$9,337/\text{MWh}$) but can be used to trade away an equivalent negative score that would be subject to a higher charge rate ($\$9,337/\text{MWh}$)
 - Bilaterals under these conditions can reduce the funds available to pay remaining overperformers
- Since PFP’s inception, only one participant has used Capacity Performance Bilaterals and only to exchange scores among resources within its own portfolio
- Capacity suppliers can still shed CSO risk through other hedging tools such as reconfiguration auctions, bilateral CSO trades, or out-of-market bilaterals



Capacity Performance Bilaterals Example

- There is more overperformance than underperformance with the BR capped at 1.0
- A participant could increase its revenue by exchanging Resource 3's (+100) Capacity Performance Score with Resource 2's (-100) score in a bilateral
 - The revenue from reducing underperformance exceeds the forgone payment for overperformance
- After the bilateral, no negative performance scores remain, and no performance charges are collected
- Resource 1 contributed 100 MW but receives \$0 CPP since no charges were collected

Case with Balancing Ratio Capped and Capacity Performance Bilaterals

		Unit	Res 1	Res 2	Res 3
1	Balancing Ratio (1.04 capped at 1)	Num	1.0	1.0	1.0
2	Capacity Supply Obligation	MW	0	1,000	2,000
3	Actual Capacity Provided	MW	100	900	2,100
4	Initial Capacity Performance Score	Num	100	-100	100
5	Capacity Performance Bilateral	Num	0	100	-100
6	Final Capacity Performance Score	Num	100	0	0
7	Charge Collections	\$	0	0	0
8	Final Capacity Performance Payment	\$	0	0	0

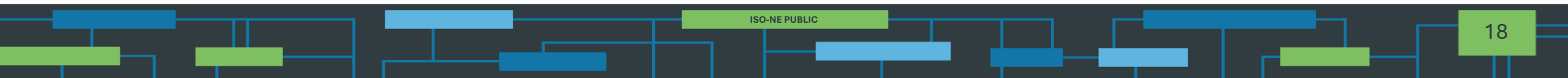
Conforming Changes to Market Power Mitigation Process

ISO's initial thinking is that no changes to Tariff language for mitigation are needed

- The ISO's proposal to allocate a deficiency to overperformers may impact resources' expected Capacity Performance Payments when the BR is capped at 1.0
- Offers and bids under review by the IMM must document "expected Capacity Performance Payments" for the resource (III.13.1.2.3.2.1.3)
- Capacity Performance Payments include PPR credits/charges, stop loss, and allocation of deficient or excess payments (III.13.7)
 - "Capacity Performance Payments as described in Section III.13.7.2 (*PPR credits/charges*), adjusted as described in Section III.13.7.3 (*stop loss*) and Section III.13.7.4 (*allocation*)"
- Therefore, the ISO's initial thinking is that no changes are needed, because the deficiency allocation will flow through III.13.7.4

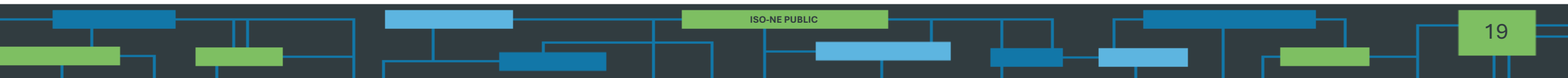
Conforming Changes for Zonal CSC Event

- The ISO is still assessing whether the Commission's order and the ISO's proposed compliance changes requires conforming changes related to zonal CSC events
- We will follow up with additional information at the April MC



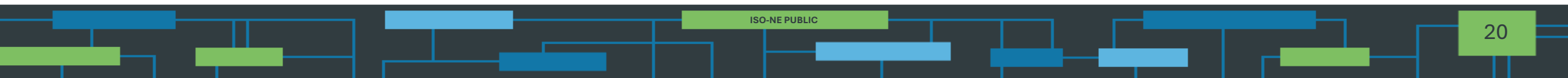
Conclusion

- Changes are required to Pay-for-Performance to comply with FERC Order under EL25-106
 - Cap the Balancing Ratio at 1.0
 - Ensure capacity resources are not charged for a share-of-system requirement greater than their CSO MW during scarcity conditions
 - When Capacity Performance Payments are deficient, reduce payments for positive performance
 - Remove the mechanism to engage in Capacity Performance Bilaterals to avoid inefficient market outcomes and further reductions to the effective PPR
- A compliance filing is required by July 21, 2026, with a refund effective date of July 25, 2025

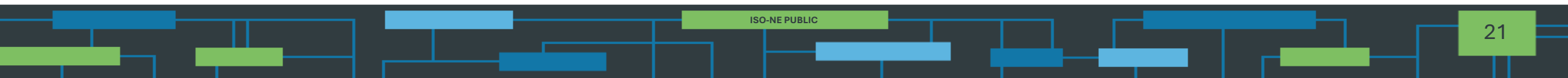


Stakeholder Schedule

Stakeholder Committee and Date	Scheduled Project Milestone
Markets Committee March 10, 2026	Summary of compliance requirements and high-level compliance plan
Markets Committee April 14-16, 2026	Additional detail on compliance plan and initial review of proposed Tariff language and any stakeholder amendments
Markets Committee May 12-13, 2026	Additional review of proposed Tariff language, stakeholder amendments, and vote
Participants Committee June 16-18, 2026	Vote



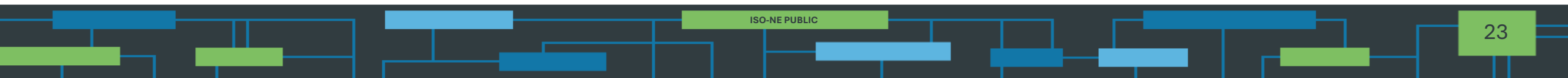
Questions



Acronyms Used in this Presentation

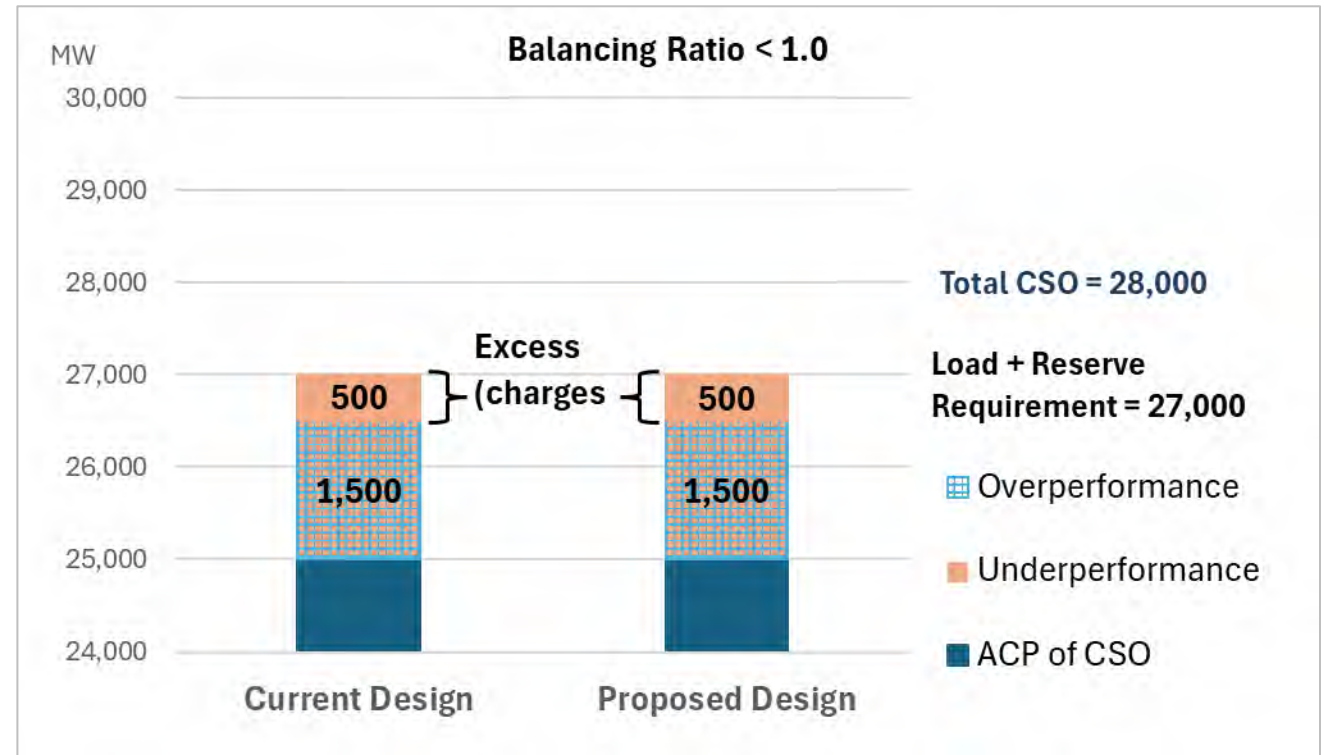
- ACP = Actual Capacity Provided
- BR = Balancing Ratio
- CPP = Capacity Performance Payment
- CPS = Capacity Performance Score
- CSC = Capacity Scarcity Condition
- CSO = Capacity Supply Obligation
- FERC = Federal Energy Regulatory Commission
- IMM = ISO-NE Internal Market Monitor
- NEPGA = New England Power Generators Association
- PFP = Pay for Performance
- PPR = Performance Payment Rate
- RR = Reserve Requirement

APPENDIX



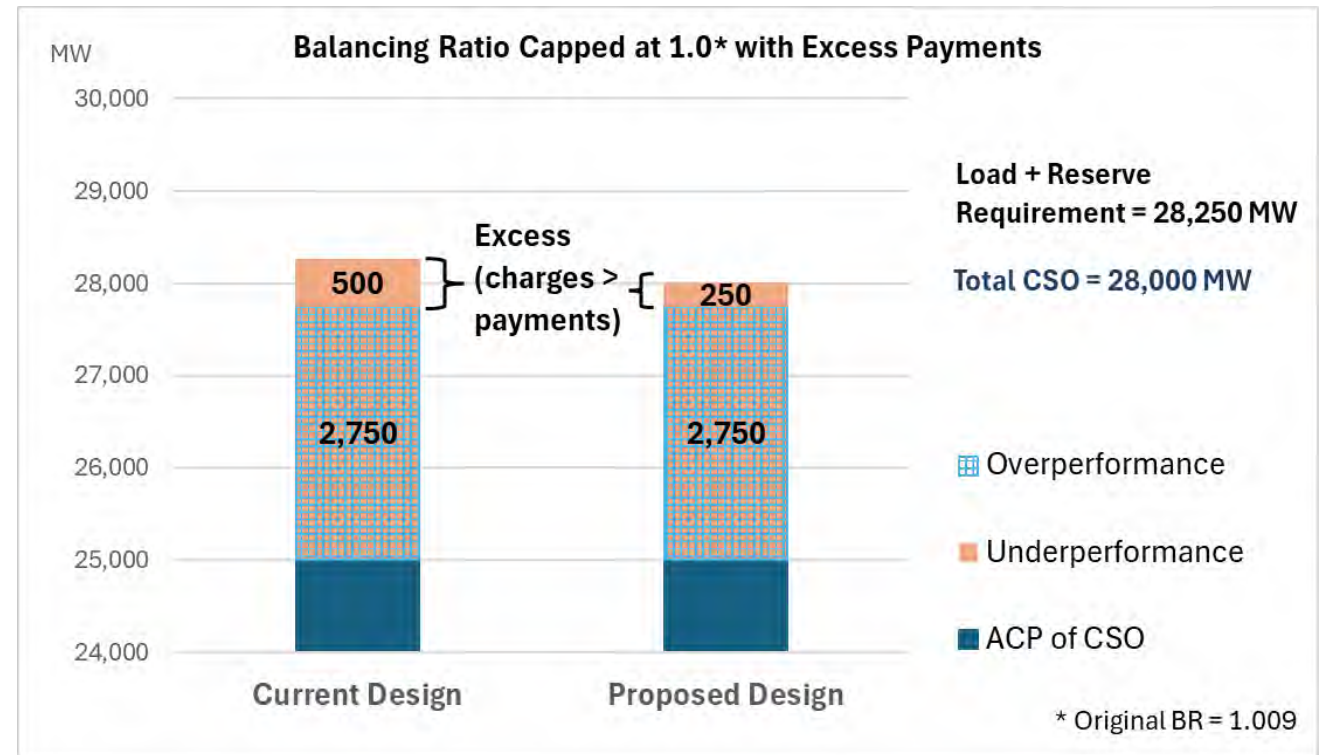
Scenario 1A: Balancing Ratio < 1.0

- Proposed design produces equivalent outcomes with Balancing Ratio < 1.0
- 2,000 MWh of underperformance
- 1,500 MWh of overperformance
- Excess Capacity Performance Payments
 - Underperformance > overperformance
 - $500 \text{ MWh} * \$9,337/\text{MWh} = \$4.7\text{M} = \$167/\text{MW}$ credit to CSO
- Effective PPR for Overperformance = $\$9,337/\text{MWh}$



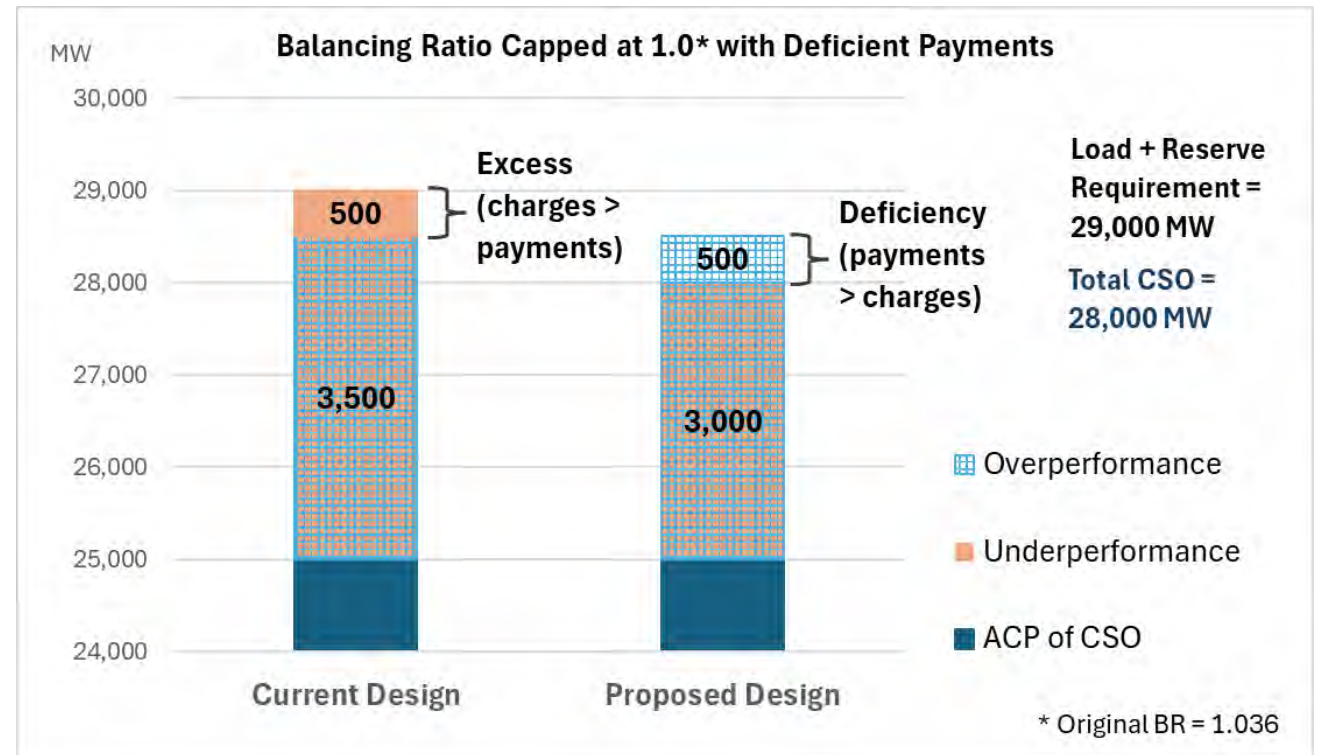
Scenario 2A: Balancing Ratio Capped at 1.0 with Excess Capacity Performance Payments

- Capacity resources performing at CSO MW are not charged when load + RR exceeds total CSO
- 3,000 MWh of underperformance with BR cap
 - 3,250 MWh when BR can exceed 1.0
- 2,750 MWh of overperformance
- Reduction in excess CPP since fewer charges collected
- Excess Capacity Performance Payments
 - Underperformance > overperformance
 - 250 MWh * \$9,337/MWh = \$2.3M = \$83/MW credit to CSO
- Effective PPR for overperformance = \$9,337/MWh
- Offsetting effects of the capped BR and lower excess funds net to the same performance payments



Scenario 3A: Balancing Ratio Capped at 1.0 with Deficient Capacity Performance Payments

- CSO resources performing at CSO MW are not charged when load + RR exceeds total CSO
- 3,000 MWh of underperformance with BR cap
 - 4,000 MWh when BR can exceed 1.0
- 3,500 MWh of overperformance
- Deficient CPP reduce payments to overperformers
 - Overperformance > underperformance
 - $-500 \text{ MWh} \times \$9,337 = -\$4.7\text{M}$ deficiency
 - $-\$4.7\text{M} / 3,500\text{MWh} = -\$1,334/\text{MWh}$ reduction in payments
- Effective PPR for overperformance = \$8,003/MWh
- Reduction in charges to capacity resources compared to current rules



Scenario 1B: Balancing Ratio < 1.0

- A one-hour event with BR < 1 results in excess CPP due to negative performance exceeding positive performance
- Excess funds are allocated proportionally to CSO resources
- The proposed changes have no effect on performance scores or performance payments

				Current, BR = 0.964				Proposed, BR = 0.964				
Res	Type	ACP (MW)	CSO (MW)	Perf Score	Prelim Payment (\$M)	Excess/ Deficit (\$M)	Perf Payment (\$M)	Perf Score	Prelim Payment (\$M)	Excess/ Deficit (\$M)	Perf Payment (\$M)	Change in Payment (\$M)
1	At CSO	500	500	18	0.167	0.083	0.250	18	0.167	0.083	0.250	0.000
2	Underperform CSO	0	500	-482	-4.502	0.083	-4.418	-482	-4.502	0.083	-4.418	0.000
3	Overperform (CSO/non)	1,500	0	1,500	14.006	0.000	14.006	1,500	14.006	0.000	14.006	0.000
4	Balance of System (CSO)	24,500	27,000	-1,536	-14.339	4.502	-9.837	-1,536	-14.339	4.502	-9.837	0.000
Total	Load+RR = 27,000 MW	26,500	28,000	-500	-4.669	4.669	0.000	-500	-4.669	4.669	0.000	0.000

Scenario 2B: Balancing Ratio Capped at 1.0 with Excess Capacity Performance Payments

- A one-hour event with BR capped at 1.0 and total Actual Capacity Provided (ACP) < total CSO results in excess CPP due to negative performance exceeding positive performance
- Excess funds are allocated proportionally to CSO holders
- Offsetting effects of the capped BR and lower excess funds net to the same performance payments

				Current, BR = 1.009				Proposed, BR cap 1.0				
Res	Type	ACP (MW)	CSO (MW)	Perf Score	Prelim Payment (\$M)	Excess/ Deficit (\$M)	Perf Payment (\$M)	Perf Score	Prelim Payment (\$M)	Excess/ Deficit (\$M)	Perf Payment (\$M)	Change in Payment (\$M)
1	At CSO	500	500	-4	-0.042	0.083	0.042	0	0.000	0.042	0.042	0.000
2	Underperform CSO	0	500	-504	-4.710	0.083	-4.627	-500	-4.669	0.042	-4.627	0.000
3	Overperform (CSO/non)	2,750	0	2,750	25.677	0.000	25.677	2,750	25.677	0.000	25.677	0.000
4	Balance of System (CSO)	24,500	27,000	-2,741	-25.593	4.502	-21.092	-2,500	-23.343	2.251	-21.092	0.000
Total	Load+RR = 28,250 MW	27,750	28,000	-500	-4.668	4.668	0.000	-250	-2.334	2.334	0.000	0.000

Scenario 3B: Balancing Ratio Capped at 1.0 with Deficient Capacity Performance Payments

- A one-hour event with BR capped at 1.0 and total ACP > total CSO results in deficient CPP due to positive performance exceeding negative performance
- Reduction in charges to capacity resources compared to current rules
- Deficient funds reduce payments to overperformers, resulting in an effective positive payment rate of \$8,003/MWh

				Current, BR = 1.036				Proposed, BR cap 1.0				
Res	Type	ACP (MW)	CSO (MW)	Perf Score	Prelim Payment (\$M)	Excess/ Deficit (\$M)	Perf Payment (\$M)	Perf Score	Prelim Payment (\$M)	Excess/ Deficit (\$M)	Perf Payment (\$M)	Change in Payment (\$M)
1	At CSO	500	500	-18	-0.167	0.083	-0.083	0	0.000	0.000	0.000	0.083
2	Underperform CSO	0	500	-518	-4.835	0.083	-4.752	-500	-4.669	0.000	-4.669	0.083
3	Overperform (CSO/non)	3,500	0	3,500	32.680	0.000	32.680	3,500	32.680	-4.669	28.011	-4.669
4	Balance of System (CSO)	24,500	27,000	-3,464	-32.346	4.502	-27.844	-2,500	-23.343	0.000	-23.343	4.502
Total	Load+RR = 29,000 MW	28,500	28,000	-500	27.678	0.167	0.000	500	4.669	-4.669	0.000	0.000



Pay-for-Performance Revisions: Balancing Ratio Compliance

*Proposed PFP Revisions for Compliance with Order to
Cap the Capacity Balancing Ratio*

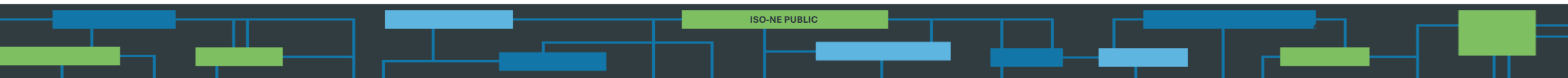
Megan Sweitzer & Enrico De Magistris

LEAD ANALYST & ECONOMIST



Proposed Effective Date: **October 1, 2026**

- On January 22, 2026, the Federal Energy Regulatory Commission (FERC) issued an [order in Docket EL25-106](#) for ISO-NE to cap the Balancing Ratio (BR) at 1.0
- The ISO presented the initial compliance plan to cap the Balancing Ratio at the March Markets Committee (MC) Meeting
- Today's discussion includes:
 - Follow up from March MC regarding additional information on stop loss and balancing fund order of operations
 - Introduce conforming changes for zonal CSC events
 - Initial review of proposed Tariff language
- A compliance filing is due by July 21, 2026, with a refund effective date of July 25, 2025

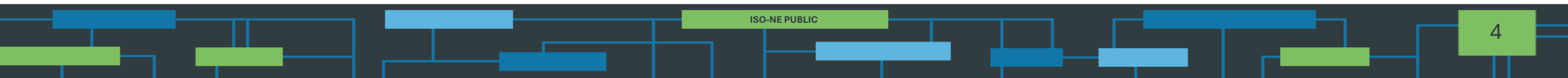


Overview of Proposal

- Cap the Capacity Balancing Ratio at 1.0 to ensure capacity resources are not charged for a share-of-system obligation higher than their Capacity Supply Obligation (CSO) MW
- Allocate deficient Capacity Performance Payments to reduce payments for overperformance
 - Allocate the deficiency proportionally by overperformance across the month
 - Provides equal payments for overperformance
- Continue to allocate excess Capacity Performance Payments to resources with a CSO proportionally by CSO MW
- Discontinue the mechanism to engage in Capacity Performance Bilaterals

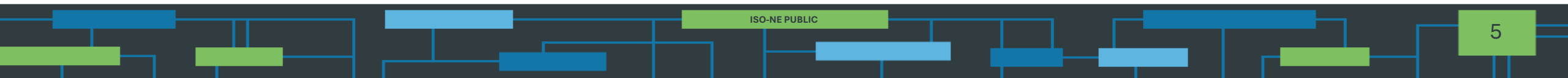
BALANCING FUND ALLOCATION

Additional details on the balancing fund allocation, stop loss, and zonal Capacity Scarcity Conditions (CSC)



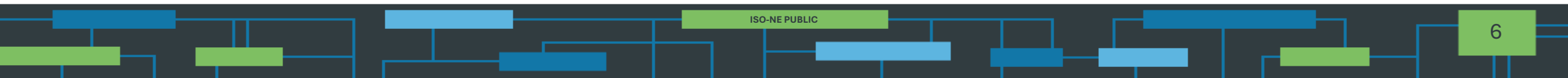
Balancing Fund and Stop Loss Allocation Process

- The ISO must separate these sources of payments to ensure that
 - A balancing fund deficiency is not charged to CSO resources
 - Stopped losses are allocated among CSO resources
- A resource's allocation from each of these sources may still have offsetting effects in the resource's monthly settlement
- The accumulation of stopped losses will not affect the size of the balancing fund, but the balancing fund allocation may influence the amount of stopped losses that accrue
 - Note: The ISO defines the balancing fund as the sum of all Capacity Performance Payments (CPP), excluding stopped losses
 - Charges not collected due to any resources reaching the stop-loss limit are calculated as a separate pool of funds charged to other CSO resources

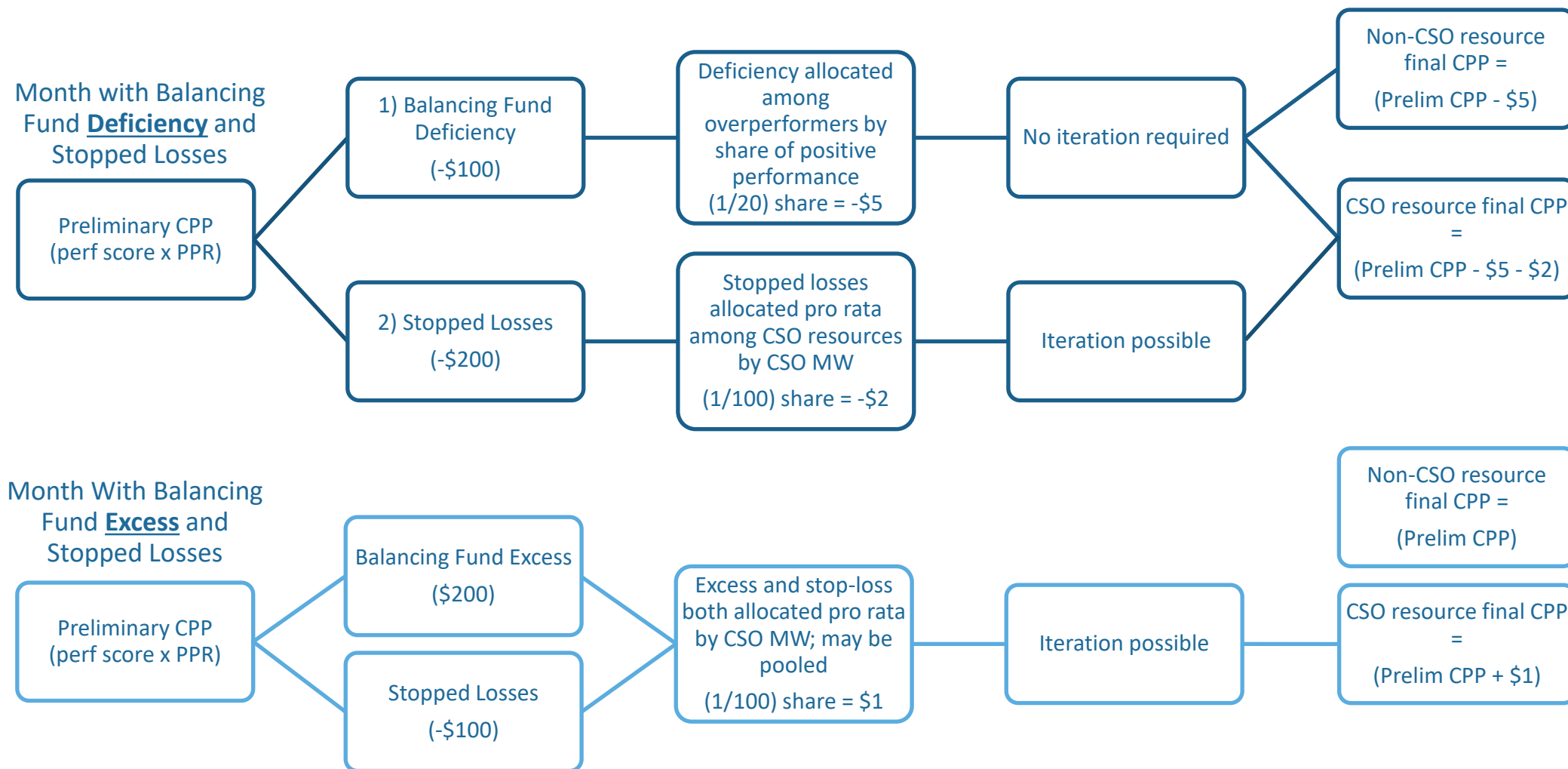


Balancing Fund and Stop Loss Allocation Process (cont.)

- If the balancing fund is deficient, the balancing fund will be allocated to reduce payments to overperformers first
 - The accumulation and distribution of stopped losses among CSO resources will not affect any resource's deficiency allocation or the “effective” PPR
- Stopped losses are then calculated and allocated through an iterative process since the allocation of stopped losses may cause a resource to reach its stop-loss limit
- If an excess balancing fund exists, no changes are required to current process
- Excess CPP and stopped losses may be pooled since both are allocated pro rata to CSO resources that have not reached their stop-loss limit



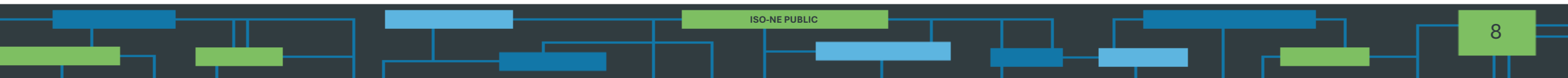
Balancing Fund and Stop Loss Allocation Process



Note: Balancing fund deficiency reduces overperformance payments first; stopped losses are allocated only among CSO resources

Balancing Fund and Stop Loss Allocation with Zonal CSC Events

- Capacity Performance Payments are pooled into a single balancing fund for the month, regardless of the occurrence of zonal CSCs
- Deficient CPP are allocated proportionally by share of positive performance scores across all intervals and Capacity Zones
 - Retains a single “effective” PPR across the month
 - Provides equal payments for equal performance across the month
- Excess CPP and stopped losses are allocated pro rata by CSO MW among all CSO resources ***subject to a CSC*** in the obligation month
 - Allocated among resources that have not reached their stop-loss limit
 - If CSC(s) occur in a single Capacity Zone in a month, excess CPP and stopped losses will be allocated pro rata by CSO MW among CSO resources in that single Capacity Zone
 - If a zonal and a system-wide CSC occur in the same month, excess CPP and stopped losses will be allocated pro rata by CSO MW among all CSO resources



Balancing Fund Allocation with Zonal CSC Events

Monthly Balancing Fund Deficiency

- Balancing fund deficiency reduces payments for overperformance equally across the month
- Single effective PPR for overperformance for the month

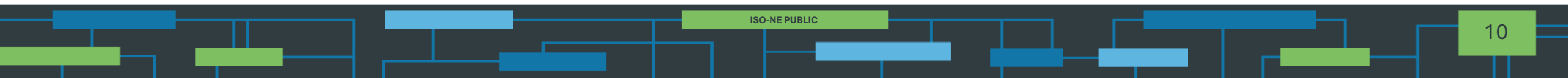
PPR=\$3,500	Event 1 (Zonal)	Event 2 (System)
Balancing Ratio	0.95	1.0 (from 1.03)
CSO	10,000	28,000
Load+RR	9,500	28,850
ACP	9,300	28,350
Hours	1	1
Underperformance	1,000	2,000
Overperformance	800	2,350
Performance Charges Accrued	3,500,000	7,000,000
Performance Payments at Full PPR	-2,800,000	-8,225,000
Balancing Fund		
Excess (+)/Deficient (-) CPP	-525,000	
Excess \$ per CSO MW	0	
Effective PPR (\$/MWh)	3,333	

Monthly Balancing Fund Excess

- Excess monthly balancing fund allows payments for overperformance at the full PPR
- Excess CPP are distributed as credit among all CSO resources subject to a CSC

PPR=\$3,500	Event 1 (Zonal)	Event 2 (System)
Balancing Ratio	1.0 (from 1.03)	0.95
CSO	10,000	28,000
Load+RR	10,300	26,600
ACP	10,100	26,100
Hours	1	1
Underperformance	1,000	2,000
Overperformance	1,100	1,500
Performance Charges Accrued	3,500,000	7,000,000
Performance Payments at Full PPR	-3,850,000	-5,250,000
Balancing Fund		
Excess (+)/Deficient (-) CPP	1,400,000	
Excess \$ per CSO MW	50	
Effective PPR (\$/MWh)	3,500	

PROPOSED TARIFF CHANGES



Summary of Proposed Tariff Changes

- Section III.13.5.3. Capacity Performance Bilaterals
 - Discontinue Capacity Performance Bilaterals
- Section III.13.7.2.3. Capacity Balancing Ratio
 - Cap the Capacity Balancing Ratio at 1.0
- Section III.13.7.4. Allocation of Deficient or Excess Capacity Performance Payments
 - Distinguish stop loss from the pool of excess or deficient Capacity Performance Payments
 - Allocate deficient Capacity Performance Payments to overperformers proportionally by monthly share of overperformance
 - Allocate excess Capacity Performance Payments pro rata by CSO MW among CSO resources subject to a CSC that have not reached their stop-loss limit
 - Allocate stopped losses pro rata by CSO MW among CSO resources subject to a CSC that have not reached their stop-loss limit
- The ISO proposes to make the same edits to the corresponding sections of III.15

Summary of Proposed Tariff Changes

Capacity Performance Bilaterals & Capacity Balancing Ratio

Tariff Section	Tariff Change	Reason for Change
III.13.5	Strike reference to Capacity Performance Bilaterals	Remove reference to discontinued Capacity Performance Bilaterals
III.13.5.3	Strike section “Capacity Performance Bilaterals”	Discontinues Capacity Performance Bilaterals to prevent a “money-for-nothing” problem
III.13.7.2.3	Insert “provided, however, that the Capacity Balancing Ratio shall not exceed a value of 1.0”	Comply with directive in FERC order

Summary of Proposed Tariff Changes

Allocation of Deficient or Excess Capacity Performance Payments

Tariff Section	Tariff Change	Reason for Change
III.13.7.4	Change to “For Capacity Scarcity Conditions as described in Section III.13.7.2.1, the ISO shall allocate deficient or excess Capacity Performance Payments as described in subsections (a), (b), and (c) below.”	Pool deficient or excess CPP into a single balancing fund for the month to ensure a uniform effective PPR across the month
III.13.7.4 (a)	Change “ the Capacity Scarcity Condition” to “ a Capacity Scarcity Condition” and strike “in the Capacity Zone”	Clarify single balancing fund for the month
III.13.7.4 (a)	Add “excluding any deficiency due to one or more resources reaching the stop-loss limit described in Section III.13.7.3”	Clarify that stopped losses are not considered in the sum of CPP
III.13.7.4 (a)	Strike “Capacity Supply Obligation.” Add “the sum of” and “positive Capacity Performance Score”	To prevent charging CSO resources beyond their obligation, a deficiency is allocated by overperformance instead of CSO MW

Summary of Proposed Tariff Changes

Allocation of Deficient or Excess Capacity Performance Payments

Tariff Section	Tariff Change	Reason for Change
III.13.7.4 (a)	Strike “excluding any resources subject to...as described in this Section III.13.7.4(a)”	Exclusions for stop loss or Energy Efficiency are not applicable for the deficiency allocation. Stop loss clarified in III.13.7.4(c).
III.13.7.4 (a), III.13.7.4 (b)	Change “will” to “shall”	Consistent language
III.13.7.4 (b)	Change “ the Capacity Scarcity Condition” to “ a Capacity Scarcity Condition” and strike “in the Capacity Zone”	Clarify single balancing fund for the month
III.13.7.4 (b)	Add “excluding any deficiency due to one or more resources reaching the stop-loss limit described in Section III.13.7.3”	Clarify that stopped losses are not considered in the sum of CPP

Summary of Proposed Tariff Changes

Allocation of Deficient or Excess Capacity Performance Payments

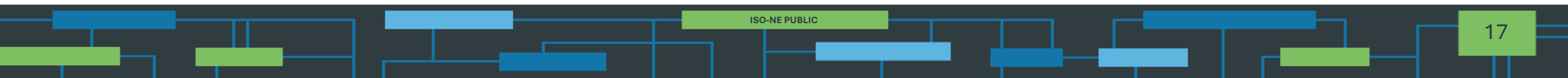
Tariff Section	Tariff Change	Reason for Change
III.13.7.4 (c)	Create new subsection (c): “If a deficiency of Capacity Performance Payments exists due to one or more resources reaching the stop-loss limit described in Section III.13.7.3, the deficiency shall be charged to all resources subject to a Capacity Scarcity Condition in an Obligation Month that have not reached their stop-loss limit (excluding any resource, or portion thereof, consisting of Energy Efficiency measures) in proportion to each resource’s Capacity Supply Obligation for the Obligation Month. If the charge described in Section III.13.7.4(a) or the charge described in this Section III.13.7.4(c) causes a resource to reach the stop-loss limit described in Section III.13.7.3, then the stop-loss limit described in Section III.13.7.3 will be applied to that resource, and the remaining deficiency will be further allocated to other resources in the same manner as described in this Section III.13.7.4(c).”	Separate the allocation of stopped losses from the allocation of deficient or excess CPP

Conclusion

- Changes are required to Pay-for-Performance to comply with FERC Order under EL25-106
 - Cap the Balancing Ratio at 1.0
 - When Capacity Performance Payments are deficient, reduce payments for positive performance to ensure capacity resources are not charged for a share-of-system requirement greater than their CSO MW during scarcity conditions
 - Continue to allocate excess Capacity Performance Payments and stopped losses to CSO resources that were subject to a CSC in the month
 - Remove the mechanism to engage in Capacity Performance Bilaterals to avoid inefficient market outcomes and further reductions to the effective PPR
- A compliance filing is required by July 21, 2026, with a refund effective date of July 25, 2025

Stakeholder Schedule

Stakeholder Committee and Date	Scheduled Project Milestone
Markets Committee March 10, 2026	Summary of compliance requirements and high-level compliance plan
Markets Committee April 14-16, 2026	Additional detail on compliance plan and initial review of proposed Tariff language
Budget and Finance Subcommittee April 17, 2026	Introduce proposed Financial Assurance revisions
Budget and Finance Subcommittee May 8, 2026	Present associated Financial Assurance Policy redlines
Markets Committee May 12-14, 2026	Additional review of proposed Tariff language and Vote
Participants Committee June 16-18, 2026	Vote



Questions





Pay-For-Performance Revisions: Financial Assurance Changes for External Transactions and Balancing Ratio Redlines

Financial Assurance redlines for revised treatment of External Transactions and Average Balancing Ratio revisions to conform with revisions made to cap the Capacity Balancing Ratio

Zach Shell

SUPERVISOR, MARKET AND CREDIT RISK

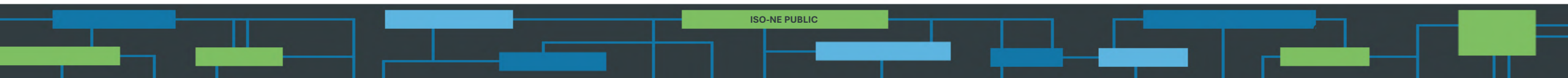


Pay-For-Performance: Financial Assurance Changes for External Transactions and Balancing Ratio

NEPOOL PARTICIPANTS COMMITTEE
JUNE 16-18, 2026 SUMMER MEETING, AGENDA ITEM #8
Attachment F
WMPP IDs:
189 & 190

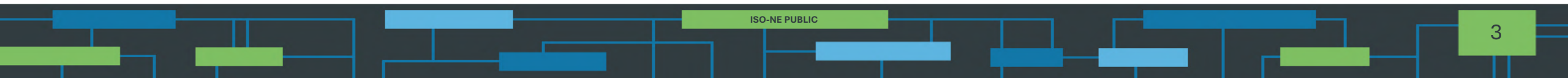
Proposed Effective Date: October 1, 2026

- During the April 17th BFS meeting, the ISO proposed updates to the Financial Assurance Policy (FAP) to conform with proposed changes to the treatment of External Transactions
 - A new Financial Assurance (FA) requirement was proposed to mitigate the risk of potential System-Backed Export (SBE) charges that may be incurred during future Capacity Scarcity Conditions (CSC)
- The ISO also discussed two proposals related to the FAP definition of Average Balancing Ratio (ABR)
 - All historical Balancing Ratios (BR) utilized within the ABR calculation will be replaced with a recalculated BR with SBE subtracted from the numerator of the BR calculation
 - Any BR used within the ABR calculation will have a maximum value of 1.0
- Today's discussion focuses on providing further details surrounding the implementation and impact of the proposals along with the redlines to the FAP



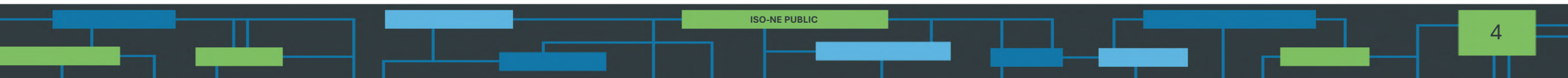
EXTERNAL TRANSACTIONS

FAP Revisions



Background

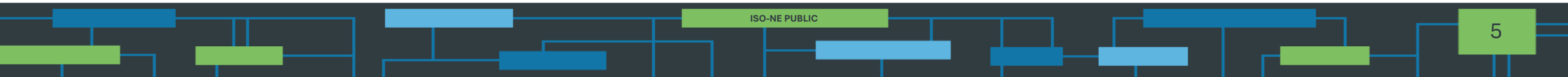
- During the April 17th BFS meeting, the ISO proposed updating the FAP to include a new financial assurance requirement
- **SBE FA = PPR * SBE MW * Scarcity Hours**
 - PPR = Performance Payment Rate
 - SBE MW = The Market Participant's Average SBE MWs across all CSCs occurring within the relevant group of months (summer, winter, shoulder) over the last 3 CCPs along with months within the relevant group prior to the current month during the current CCP
 - Scarcity Hours = The average amount of monthly CSC hours across all CSCs occurring within the relevant group of months (summer, winter, shoulder) over the last 3 CCPs along with months within the relevant group prior to the current month during the current CCP



Proposal - Updated

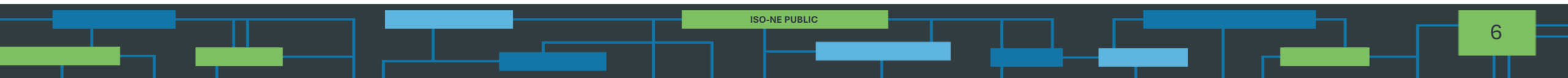
- **SBE FA = (PPR * SBE MW * Scarcity Hours) – MEC⁽¹⁾ – PMEC⁽¹⁾**
- PPR = Performance Payment Rate
- SBE MW = the Designated FCM Participant's average MW of System-Backed Exports across all Capacity Scarcity Conditions in the relevant group of months in the three Capacity Commitment Periods immediately preceding the current Capacity Commitment Period and those occurring in the months within the relevant group that are prior to the current month of the current Capacity Commitment Period, as the data becomes available; **provided, however, that, beginning on October 1, 2026, data from Capacity Scarcity Conditions that occurred prior to October 1, 2026 shall no longer be used once data is available from a Capacity Scarcity Condition in the relevant group of months in a prior Capacity Commitment Period or a Capacity Scarcity Condition in the months within the relevant group that are prior to the current month of the current Capacity Commitment Period.**
- Scarcity Hours = the **highest** total number of hours in which a Capacity Scarcity Condition occurred during any month within the relevant group of months in the three Capacity Commitment Periods immediately preceding the current Capacity Commitment Period and those occurring in the months within the relevant group that are prior to the current month of the current Capacity Commitment Period, as the data becomes available.
- **MEC (Monthly Export Charges) = System-Backed Export charges incurred in previous months, which have not yet been invoiced in instances where the MEC is a credit to the Designated FCM Participant or have not yet been invoiced and paid in instances where the MEC is a charge to the Designated FCM Participant. The MEC is estimated from the first day of the current month until it is replaced by the actual settled MEC value when settlement is complete.**
- **PMEC (Preliminary Monthly Export Charges) = estimated System-Backed Export charges incurred in the current month. Where the estimated System-Backed Export charges shall be updated three (3) days after publication of the applicable report on the Market Information Server.**

(1) MEC and PMEC are subtracted because incurred charges are negative numbers, therefore subtracted them within the formula will increase SBE FA



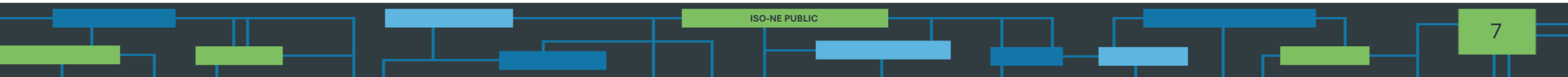
Example: SBE FA Calculation

- **SBE FA = (PPR * SBE MW * Scarcity Hours) – MEC – PMEC**
- Scenario
 - There are 2 months with CSCs within the lookback period for the relevant season
 - Neither the current month nor the prior month had CSCs; therefore, **MEC and PMEC are both zero**
 - The first month had a total of 2 scarcity hours (24 CSC intervals) where the MP exported an average of 100 MW
 - The second month had 1 scarcity hour (12 CSC intervals) where the MP exported an average of 40 MW
 - The PPR is \$3,500/ MWh
- The SBE MW used in the SBE FA calculation is a weighted average of SBEs during all scarcity hours. It is calculated by weighting each month's average SBEs by the number of scarcity hours and dividing by the total scarcity hours
 - **$((100 \text{ MW} * 2 \text{ hours}) + (40 \text{ MW} * 1 \text{ scarcity hour})) / 3 \text{ hours} = 80 \text{ MW}$**
- The Scarcity Hours used in the SBE FA calculation are 2, because that was the highest number of scarcity hours in any single month during which CSCs occurred
- Using a PPR of \$3,500, an SBE MW of 80, and 2 Scarcity Hours, the resulting SBE FA amount is
 - **$\$3,500 \text{ PPR} * 80 \text{ SBE MW} * 2 \text{ Scarcity Hours} = \$560,000$**



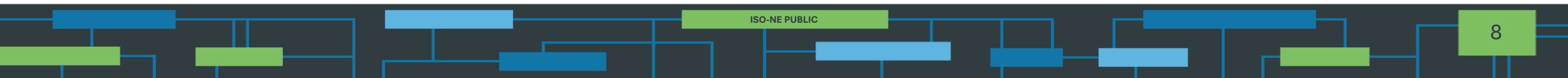
Impact of Proposal

- The proposed change to update the FAP to include the SBE FA requirement will result in total additional FA requirements for the market of ~\$1.6MM on average over the course of the first year it becomes effective (based on existing data, without respect for how future CSC events may alter FA requirements)
- The proposal only impacts the FA requirements for MPs that have historically had SBE transactions during CSCs within the last 3 years. MPs that have not had SBE transactions during any CSCs within the last 3 years will have no impact to their FA requirements
 - Likewise, MPs that showcase no SBE activity during future CSCs will have no additional FA requirements at that time



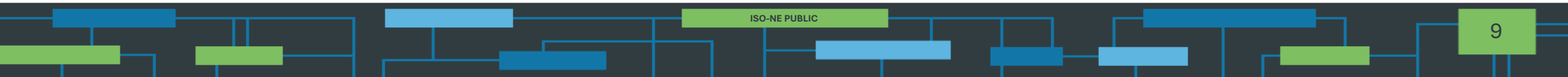
BALANCING RATIO

FAP Revisions



Background

- At the April 17th BFS, the ISO proposed an update to the FAP definition of Average Balancing Ratio (ABR) to reflect a cap of all historical BRs utilized within the ABR calculation at 1.0 to comply with FERC's order
- The ISO also proposed an update to the FAP definition of ABR to reflect that any BR used within the ABR calculation be replaced with a recalculated BR with SBEs subtracted from the numerator to conform with the proposed change to the BR formula

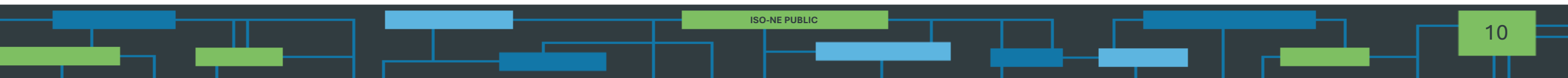


Example: ABR Calculation

- The below data represents how the BRs from each CSC event within the lookback period will be recalculated for purposes of utilization within the ABR calculation

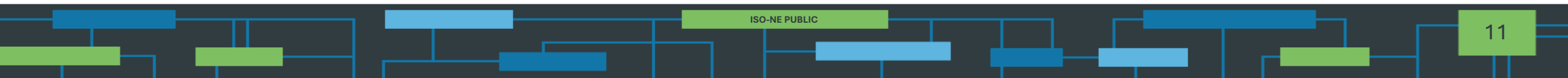
CSC Event Date	Season	Number of CSC Intervals	Original BR	Recalculated BR (SBE's removed and cap of 1.0)
Jun 2024	Summer	6 (0.5 hours)	0.869	0.847
Aug 2024	Summer	22 (1.833 hours)	0.903	0.883
Jun 2025	Summer	37 (3.083 hours)	1.031	0.999
Nov 2025	Shoulder	6 (0.5 hours)	0.696	0.634

- The ABR for each season during the first 12 months upon which the proposal is effective (assuming no additional CSC events occur) will therefore be:
 - Summer ABR = $((0.847 * 6) + (0.883 * 22) + (0.999 * 37)) / 65 = \mathbf{0.946}$
 - Winter ABR = **0.7** (default value as defined in the FAP in the absence of a CSC within the lookback period)
 - Shoulder ABR = $(0.634 * 6) / 6 = \mathbf{0.634}$



FINANCIAL ASSURANCE POLICY REDLINES

FAP Revisions



FAP Redlines: SBE FA

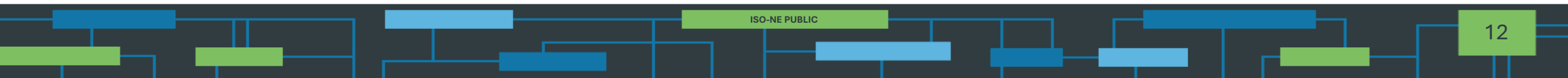
A Designated FCM Participant with System-Backed Export transactions, as defined in Section III.13.7.2.A and Section III.15.8.2.A of Market Rule 1, must include SBE Financial Assurance in the calculation of its FCM Financial Assurance Requirements under the ISO New England Financial Assurance Policy.

SBE Financial Assurance is calculated according to the following formula for a Designated FCM Participant with System-Backed Export transactions.

$$\text{SBE Financial Assurance} = (\text{PPR} * \text{SBE MW} * \text{Scarcity Hours}) - \text{MEC} - \text{PMEC}$$

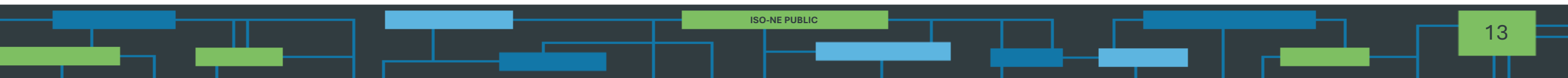
Where:

PPR is the Performance Payment Rate as defined in Section III.13.7.2.5 and Section III.15.8.2.5 of Market Rule 1.



FAP Redlines: SBE FA

SBE MW equals the Designated FCM Participant's average MW of System-Backed Exports across all Capacity Scarcity Conditions in the relevant group of months in the three Capacity Commitment Periods immediately preceding the current Capacity Commitment Period and those occurring in the months within the relevant group that are prior to the current month of the current Capacity Commitment Period, as the data becomes available; provided, however, that, beginning on October 1, 2026, data from Capacity Scarcity Conditions that occurred prior to October 1, 2026 shall no longer be used once data is available from a Capacity Scarcity Condition in the relevant group of months in a prior Capacity Commitment Period or a Capacity Scarcity Condition in the months within the relevant group that are prior to the current month of the current Capacity Commitment Period. Three separate groups of months shall be used for this purpose: June through September, December through February, and all other months.



FAP Redlines: SBE FA

Scarcity Hours equals the highest total number of hours in which a Capacity Scarcity Condition occurred during any month within the relevant group of months in the three Capacity Commitment Periods immediately preceding the current Capacity Commitment Period and those occurring in the months within the relevant group that are prior to the current month of the current Capacity Commitment Period, as the data becomes available. Three separate groups of months shall be used for this purpose: June through September, December through February, and all other months.

MEC (monthly export charges) equals System-Backed Export charges incurred in previous months, which have not yet been invoiced in instances where the MEC is a credit to the Designated FCM Participant or have not yet been invoiced and paid in instances where the MEC is a charge to the Designated FCM Participant. The MEC is estimated from the first day of the current month until it is replaced by the actual settled MEC value when settlement is complete.

PMEC (preliminary export charges) equals estimated System-Backed Export charges incurred in the current month. Where the estimated System-Backed Export charges shall be updated three (3) days after publication of the applicable report⁽¹⁾ on the Market Information Server.

(1) The ISO may update this text to state the name of the report.

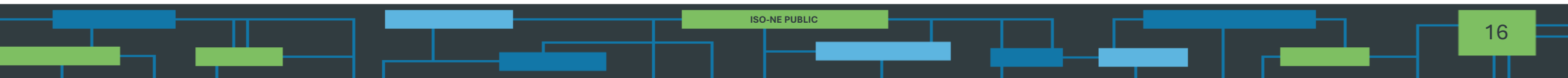
FAP Redlines: ABR

- ABR (average balancing ratio) is the duration-weighted average of all of the system-wide Capacity Balancing Ratios calculated for each system-wide Capacity Scarcity Condition occurring in the relevant group of months in the three Capacity Commitment Periods immediately preceding the current Capacity Commitment Period and those occurring in the months within the relevant group that are prior to the current month of the current Capacity Commitment Period, as the data becomes available. **For the purpose of calculating the ABR, all Capacity Balancing Ratios, including Capacity Balancing Ratios for Capacity Scarcity Conditions that occurred in past Capacity Commitment Periods or in the months within the relevant group that are prior to the current month of the current Capacity Commitment Period, shall be calculated utilizing the Capacity Balancing Ratio formula that is currently effective, as described in Section III.13.7.2.3 or Section III.15.8.2.3 of Market Rule 1⁽¹⁾.** Three separate groups of months shall be used for this purpose: June through September, December through February, and all other months. Until data exists to calculate this number, the temporary ABR for June through September shall equal 0.90; the temporary ABR for December through February shall equal 0.70; and the temporary ABR for all other months shall equal 0.60.

(1) The ISO proposes to include this sentence in the redlines for both the External Transactions and Balancing Ratio proposals. All other redlines will be included in the External Transactions proposal only. Each proposal will be filed with the Federal Energy Regulatory Commission separately.

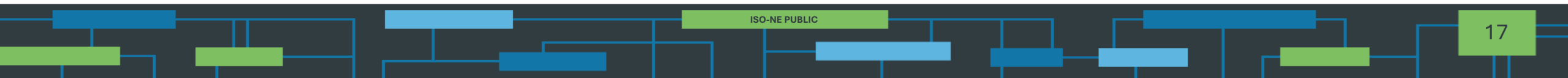
FAP Redlines: Administrative Changes

- Any Lead Market Participant, including any Provisional Member that is a Lead Market Participant, transacting in the Forward Capacity Market that is otherwise required to provide additional financial assurance under the ISO New England Financial Assurance Policy, **and any Market Participant with System-Backed Export transactions** (each a “Designated FCM Participant”), is required to provide additional financial assurance meeting the requirements of Section X below in the amounts described in this Section VII (such amounts being referred to in the ISO New England Financial Assurance Policy as the “FCM Financial Assurance Requirements”). If the Lead Market Participant for a Resource changes, then the new Lead Market Participant for the Resource shall become the Designated FCM Participant.



FAP Redlines: Administrative Changes

- a Market Participant's "Non-Hourly Requirements" at any time will be determined by averaging that Market Participant's Non-Hourly Charges but not include: (A) the amount due from or to such Market Participant for FTR transactions, (B) any amounts due from such Market Participant for the Forward Capacity Market **or System-Backed Export transactions**, (C) any amounts due under Section 14.1 of the RNA, (D) any amounts due for NEPOOL GIS API Fees, and (E) the amount of any Qualification Process Cost Reimbursement Deposit (including the annual true-up of that amount) due from such Market Participant) over the two most recently invoiced calendar months; provided that such Non-Hourly Requirements shall in no event be less than zero;



Conclusion

- The ISO is proposing FAP changes to mitigate the risk of a market participant defaulting on SBE charges incurred during CSCs
- The ISO is also proposing to change the FAP definition of ABR to include the 1.0 BR cap and utilize recalculated historical BR values based on the newly proposed BR formula
- The ISO will file the BR compliance proposal by July 21, 2026 and will propose an October 1, 2026 effective date
- The ISO plans to file the External Transactions proposal in July 2026, with an October 1, 2026 proposed effective date

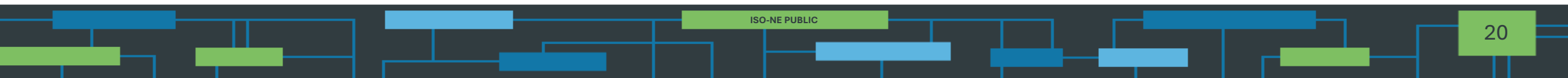
Stakeholder Schedule

Stakeholder Committee and Date	Scheduled Project Milestone
Budget and Finance Subcommittee April 17, 2026	Introduce proposed Financial Assurance revisions for treatment of external transactions and Balancing Ratio cap under Pay-for-Performance
Budget and Finance Subcommittee May 8, 2026	Present associated FAP redlines
Budget and Finance Subcommittee June 5, 2026	Present related Billing Policy conforming change
Participants Committee June 16-18, 2026	Vote

The ISO will file the BR compliance proposal by July 21, 2026 and will propose an October 1, 2026 effective date.

The ISO plans to file the External Transactions proposal in July 2026, with an October 1, 2026 proposed effective date.

Questions



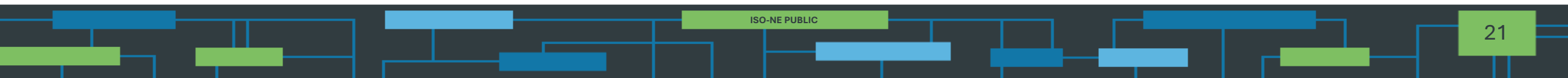
About the Presenter

Zach Shell

Supervisor, Market and Credit Risk

ISO New England

zshell@iso-ne.com



MEMORANDUM

TO: NEPOOL Participants Committee Members and Alternates
FROM: NEPOOL Counsel
DATE: June 9, 2026
RE: Performance Payment Rate Proposal

At its June 16–18, 2026 Summer Meeting, the Participants Committee will be asked to support the ISO’s proposed Tariff revisions to reduce the Performance Payment Rate (PPR) from \$9,337/MWh to \$3,500/MWh (PPR Proposal). This memorandum provides a high-level overview of the proposal, summarizes the stakeholder process to date, including amendments the Markets Committee considered, and includes the following attachments:

- Attachment A: Section III.13.7 and Section III.15 Redlines, as recommended by the Markets Committee
- Attachment B: ISO-NE’s May 12–14, 2026 Presentation
- Attachment C: Markets Committee Notice of Actions, dated May 15, 2026
- Attachment D: FirstLight’s May 12–14, 2026 Presentation
- Attachment E: JERA America’s Presentation

OVERVIEW

As part of the Pay-for-Performance design, the PPR is the Tariff-prescribed settlement rate used to calculate performance payments and charges during Capacity Scarcity Conditions. The initial PPR was administratively established at \$2,000/MWh for Forward Capacity Auctions (FCAs) 9 through 11. For FCAs 12 through 14, the PPR was administratively set at \$3,500/MWh. Beginning with FCA 15, however, the PPR was determined pursuant to a formula, resulting in a rate of \$5,455/MWh. For FCA 16 and subsequent auctions, the formula produced a PPR of \$9,377/MWh, which remains the current rate.

Following its evaluation of expressed concerns regarding the level of financial risk imposed on resources and associated consumer cost impacts with the current PPR, the ISO proposed reducing the PPR to \$3,500/MWh. Additional information regarding the ISO’s rationale is provided in Attachment B.

STAKEHOLDER PROCESS

At its May 12–14 meeting, the Markets Committee considered the Tariff revisions included in Attachment A, as well as two proposed amendments to the ISO’s proposal. The first motion to amend (FirstLight amendment) failed to pass, with a 30.79 % Vote in favor.¹ The second motion to amend (JERA amendment) failed to pass, with a 52.2% Vote in favor.² The

¹ See Markets Committee Notice of Actions, Attachment C, at 2.

² *Id.* at 3.

ISO's unamended proposal was recommended for Participants Committee support, with an 82.23% Vote in favor.³

The two amendments the Markets Committee considered are summarized below.

1. FirstLight Amendment – Aligning the PPR Reduction with the Start of the Capacity Commitment Period (CCP) 28/29

FirstLight proposed amending the ISO's proposal so that the reduction in the PPR to \$3,500/MWh would become effective at the start of CCP 28/29 (June 1, 2028). This amendment did not receive Markets Committee support. Attachment D provides more information regarding the FirstLight Amendment. FirstLight has informed us that it intends to seek a Participants Committee vote on its Amendment and has provided a presentation, included with Attachment D, for Participants Committee consideration.

2. Canal Marketing (JERA) – One-Time Evaluation of an Alternative PPR Structure

JERA proposed adding a Tariff provision requiring the ISO to evaluate the PPR and issue a report by December 15, 2027. The evaluation would assess whether a graduated PPR structure, varying based on load levels and/or the severity of reserve shortages, would be appropriate. This amendment also did not receive Markets Committee support. JERA has informed us that it does not intend to offer its Markets Committee amendment at the June 16 Participants Committee meeting.

Instead, as described below, JERA intends to seek approval of a resolution that would support a commitment by the ISO in the filing of its PPR Proposal with the FERC (or in the absence of that commitment by the ISO, a request that the FERC direct the ISO in its order on the PPR Proposal) to conduct a further assessment of the Capacity Performance Payment Rate structure (see “Further Assessment Resolution” on next page). Attachment E provides additional information on JERA's Further Assessment Resolution.

PLANNED PROCESS FOR PARTICIPANTS COMMITTEE ACTION

The Participants Committee will begin its consideration of this matter with a motion to approve the Markets Committee-recommended PPR Proposal. The following form of resolution could be used for Participants Committee action on the Main Motion:

³ *Id.*

RESOLVED, that the Participants Committee supports ISO-NE's PPR Proposal and related revisions to Section III.13.7 and Section III.15 of the Transmission, Markets, and Services Tariff, as recommended by the Markets Committee at its May 2026 meeting, together with [any changes agreed to by the Participants Committee at this meeting and] such non-substantive changes as may be approved by the Chair and Vice-Chair of the Markets Committee.
is provided below.

After the Main Motion has been moved and duly seconded, FirstLight will have the opportunity to offer its amendment to the PPR Proposal. Approval of the FirstLight Amendment will require a Participants Committee vote of 60% or greater.

The Main Motion, as amended or if unamended, would then be voted. A Participants Committee vote of 60% or greater will be required for NEPOOL approval.

Further Assessment Resolution

Following action on the Main Motion, JERA has indicated its intention to offer its Further Assessment Resolution to build upon the Participants Committee's action on the underlying Main Motion:

FURTHER RESOLVED, that the Participants Committee requests a commitment by ISO New England (ISO) in the filing of its PPR Proposal with the Federal Energy Regulatory Commission (FERC) (or in the absence of that commitment by the ISO, a request that the FERC direct the ISO in its order on the PPR Proposal) to conduct a further assessment of whether the Capacity Performance Payment Rate structure should be revised in the future to incorporate a graduated structure tied to load levels, reserve shortage severity, and/or a similar mechanism, with that assessment to be completed and provided to the NEPOOL Markets Committee no later than December 2027.

To be approved, JERA's Further Assessment Resolution will require a Participants Committee vote of 66 2/3% or greater.

III.13.7. Performance, Payments and Charges in the FCM.

Revenue in the Forward Capacity Market for resources providing capacity shall be composed of Capacity Base Payments as described in Section III.13.7.1 and Capacity Performance Payments as described in Section III.13.7.2, adjusted as described in Section III.13.7.3 and Section III.13.7.4. Market Participants with a Capacity Load Obligation will be subject to charges as described in Section III.13.7.5.

In the event of a change in the Lead Market Participant for a resource that has a Capacity Supply Obligation, the Capacity Supply Obligation shall remain associated with the resource and the new Lead Market Participant for the resource shall be bound by all provisions of this Section III.13 arising from such Capacity Supply Obligation. The Lead Market Participant for the resource at the start of an Obligation Month shall be responsible for all payments and charges associated with that resource in that Obligation Month.

III.13.7.1. Capacity Base Payments.

Resources acquiring or shedding a Capacity Supply Obligation for the Obligation Month shall receive a Capacity Base Payment for the Obligation Month reflecting the payments and charges described in Section III.13.7.1.1.

III.13.7.1.1. Payments and Charges Reflecting Capacity Supply Obligations.

Each resource that has: (i) cleared in a Forward Capacity Auction, except for the portion of resources designated as Self-Supplied FCA Resources; (ii) cleared in a reconfiguration auction; or (iii) entered into a Capacity Supply Obligation Bilateral shall be entitled to a monthly payment or charge during the Capacity Commitment Period. Each monthly payment and charge listed in Section III.13.7.1.1 (a) through (d) below will be divided by the number of days in the month to derive a daily settlement value.

(a) **Forward Capacity Auction.** For a resource whose offer has cleared in a Forward Capacity Auction, the monthly capacity payment shall equal the product of its cleared capacity and the Capacity Clearing Price in the Capacity Zone in which the resource is located as adjusted by applicable indexing for resources with additional Capacity Commitment Period elections pursuant to Section III.13.1.1.2.2.4 in the manner described below. For a resource that has elected to have the Capacity Clearing Price and the Capacity Supply Obligation apply for more than one Capacity Commitment Period, payments associated with the Capacity Supply Obligation and Capacity Clearing Price (indexed using the Handy-Whitman Index of Public Utility Construction Costs in effect as of December 31 of the year preceding the Capacity Commitment Period) shall continue to apply after the Capacity Commitment Period associated

- (i) In any Capacity Zone subject to Reserve Constraint Penalty Factor pricing associated with both the Minimum Total Reserve Requirement and the Ten-Minute Reserve Requirement, but not the Zonal Reserve Requirement, the Capacity Balancing Ratio shall be calculated as described in Section III.13.7.2.3(a) for resources in that Capacity Zone.
- (ii) In any Capacity Zone subject to Reserve Constraint Penalty Factor pricing associated with both the Ten-Minute Reserve Requirement and the Zonal Reserve Requirement, but not the Minimum Total Reserve Requirement, the Capacity Balancing Ratio for resources in that Capacity Zone shall be the higher of the Capacity Balancing Ratio calculated as described in Section III.13.7.2.3(b) and the Capacity Balancing Ratio calculated as described in Section III.13.7.2.3(c).
- (iii) In any Capacity Zone subject to Reserve Constraint Penalty Factor pricing associated with the Minimum Total Reserve Requirement and the Zonal Reserve Requirement (regardless of whether the Capacity Zone is also subject to Reserve Constraint Penalty Factor pricing associated with the Ten-Minute Reserve Requirement), the Capacity Balancing Ratio for resources in that Capacity Zone shall be the higher of the Capacity Balancing Ratio calculated as described in Section III.13.7.2.3(a) and the Capacity Balancing Ratio calculated as described in Section III.13.7.2.3(c).

III.13.7.2.4 Capacity Performance Score.

Each resource, whether or not it has a Capacity Supply Obligation, will be assigned a Capacity Performance Score for each five-minute interval in which a Capacity Scarcity Condition exists in the Capacity Zone in which the resource is located. A resource's Capacity Performance Score for the interval shall equal the resource's Actual Capacity Provided during the interval (with the Actual Capacity Provided of Energy Efficiency measures being zero, as specified in Section III.13.7.2.2(c)(i)) minus the product of the resource's Capacity Supply Obligation (which for this purpose shall not be less than zero) and the applicable Capacity Balancing Ratio; provided, however, that for an On-Peak Demand Resource or a Seasonal Peak Demand Resource, the Capacity Supply Obligation associated with any Energy Efficiency measures shall be excluded from the calculation of the resource's Capacity Performance Score. The resulting Capacity Performance Score may be positive, zero, or negative.

III.13.7.2.5 Capacity Performance Payment Rate.

For the three Capacity Commitment Periods beginning June 1, 2018 and ending May 31, 2021, the Capacity Performance Payment Rate shall be \$2000/MWh. For the three Capacity Commitment Periods beginning June 1, 2021 and ending May 31, 2024, the Capacity Performance Payment Rate shall be \$3500/MWh. For the Capacity Commitment Period beginning on June 1, 2024 and ending on May 31, 2025, the Capacity Performance Payment Rate shall be \$5455/MWh. For the ~~Capacity Commitment~~ pPeriod beginning on June 1, 2025 and ending on ~~August~~May 31, 2026 ~~and thereafter~~, the Capacity Performance Payment Rate shall be \$9337/MWh. Thereafter, the Capacity Performance Payment Rate shall be \$3500/MWh. The ISO shall review the Capacity Performance Payment Rate in the stakeholder process as needed and shall file with the Commission a new Capacity Performance Payment Rate if and as appropriate.

III.13.7.2.6 Calculation of Capacity Performance Payments.

For each resource, whether or not it has a Capacity Supply Obligation, the ISO shall calculate a Capacity Performance Payment for each five-minute interval in which a Capacity Scarcity Condition exists in the Capacity Zone in which the resource is located. A resource's Capacity Performance Payment for an interval shall equal the resource's Capacity Performance Score for the interval multiplied by the Capacity Performance Payment Rate. The resulting Capacity Performance Payment for an interval may be positive or negative.

III.13.7.3 Monthly Capacity Payment and Capacity Stop-Loss Mechanism.

Each resource's Monthly Capacity Payment for an Obligation Month, which may be positive or negative, shall be the sum of the resource's Capacity Base Payment for the Obligation Month plus the sum of the resource's Capacity Performance Payments for all five-minute intervals in the Obligation Month, except as provided in Section III.13.7.3.1 and Section III.13.7.3.2 below.

III.13.7.3.1 Monthly Stop-Loss.

If the sum of the resource's Capacity Performance Payments (excluding any Capacity Performance Payments associated with Actual Capacity Provided above the resource's Capacity Supply Obligation in any interval) for all five-minute intervals in the Obligation Month is negative, the amount subtracted from the resource's Capacity Base Payment for the Obligation Month will be limited to an amount equal to the product of the applicable Forward Capacity Auction Starting Price multiplied by the resource's Capacity Supply Obligation for the Obligation Month (or, in the case of a resource subject to a multi-year Capacity Commitment Period election made in a Forward Capacity Auction prior to the ninth Forward Capacity Auction as described in Sections III.13.1.1.2.2.4 and III.13.1.4.1.1.2.7, the amount subtracted from the

III.15. Annual Capacity Market.

(a) Annual Capacity Market Overview.

The ISO shall administer an annual market for capacity (Annual Capacity Market) in accordance with the provisions of this Section III.15. For each one-year period from June 1 through May 31, starting with the period June 1, 2028 to May 31, 2029, for which Capacity Supply Obligations are assumed and payments are made in the Annual Capacity Market (“Capacity Commitment Period”), the ISO shall conduct an Annual Capacity Auction in accordance with the provisions of Section III.15.4 to procure the amount of capacity needed in the New England Control Area and in each modeled Capacity Zone during the Capacity Commitment Period, as determined in accordance with the provisions of Section III.12. To be eligible to assume a Capacity Supply Obligation for a Capacity Commitment Period through the Annual Capacity Auction, a resource must have Qualified Capacity resulting from the Annual Capacity Auction qualification process in accordance with the provisions of Sections III.15.2 and III.15.3. Obligations associated with the Annual Capacity Market may be traded during ISO-administered Monthly Reconfiguration Auctions and monthly bilateral transactions, in accordance with Section III.15.5 and Section III.15.6, respectively. The obligations of resources with Capacity Supply Obligations resulting from the Annual Capacity Auction, Monthly Reconfiguration Auctions, and monthly bilateral transactions are set forth in Section III.15.7. Payments and charges resulting from participation in the Annual Capacity Market, Monthly Reconfiguration Auctions, and bilateral transactions, as well as Capacity Performance Payments, are set forth in Section III.15.8. The publication of auction-related information is set forth in Section III.15.9.

(b) Capacity Auction Calendar.

Beginning with the timeline for the Capacity Commitment Period beginning on June 1, 2028, and for each Capacity Commitment Period thereafter, the ISO shall publish a calendar of dates and deadlines for the administration of the Capacity Market, with the dates and deadlines being consistent for each Annual Capacity Auction cycle. The Capacity Auction Calendar shall include specific dates and deadlines for all such Capacity Market dates and deadlines defined in this Section III.15 and related Tariff provisions. The following defines several milestone dates and deadlines.

- (1) the Qualification Data Submission Deadline for the Annual Capacity Auction shall occur during the month of February;

(2) the Capacity Demonstration Deadline for the Annual Capacity Auction shall occur during the month of April; and

(3) the Annual Capacity Auction shall occur during the month of May.

(c) Modification of Capacity Auction Calendar.

The ISO may, on a prospective basis, reasonably revise any date or deadline in the Capacity Auction Calendar with written notice of such revision to each Governance Participant in the manner specified in Section 17.11(b) of the Participants Agreement prior to the occurrence of the date or deadline being revised. In the event a Market Participant fails to meet a deadline in the Capacity Auction Calendar for submission of information or data, the ISO shall extend such deadline for that Market Participant upon receipt of an order from the Commission granting the Market Participant's request for a waiver of such deadline for good cause shown. In no event shall a date or deadline be extended, prospectively by the ISO or retroactively by filing of a Market Participant, should doing so interfere with the ISO's effective administration of the Capacity Market.

(d) Effectiveness for the 2028-2029 Capacity Commitment Period and Thereafter.

The provisions of this Section III.15 are effective for the Capacity Commitment Period that runs from June 1, 2028 through May 31, 2029 and all Capacity Commitment Periods thereafter. Unless otherwise expressly stated, the provisions of this Section III.15 are not applicable to the Forward Capacity Market. Section III.13, addressing the administration of the Forward Capacity Market, shall continue to be effective for Capacity Commitment Periods through May 31, 2028. Unless otherwise expressly stated, the provisions of Section III.13 are not applicable to the Annual Capacity Market, Monthly Reconfiguration Auctions and monthly bilateral transactions addressed in this Section III.15 of Market Rule 1.

Section III.15.8.2.3(b) and the Capacity Balancing Ratio calculated as described in Section III.15.8.2.3(c).

(iii) In any Capacity Zone subject to Reserve Constraint Penalty Factor pricing associated with the Minimum Total Reserve Requirement and the Zonal Reserve Requirement (regardless of whether the Capacity Zone is also subject to Reserve Constraint Penalty Factor pricing associated with the Ten-Minute Reserve Requirement), the Capacity Balancing Ratio for resources in that Capacity Zone shall be the higher of the Capacity Balancing Ratio calculated as described in Section III.15.8.2.3(a) and the Capacity Balancing Ratio calculated as described in Section III.15.8.2.3(c).

III.15.8.2.4. Capacity Performance Score.

Each resource, whether or not it has a Capacity Supply Obligation, will be assigned a Capacity Performance Score for each five-minute interval in which a Capacity Scarcity Condition exists in the Capacity Zone in which the resource is located. A resource's Capacity Performance Score for the interval shall equal the resource's Actual Capacity Provided during the interval (with the Actual Capacity Provided of Energy Efficiency measures being zero, as specified in Section III.15.8.2.2(c)(i)) minus the product of the resource's Capacity Supply Obligation (which for this purpose shall not be less than zero) and the applicable Capacity Balancing Ratio; provided, however, that for an On-Peak Demand Capacity Resource or a Seasonal Peak Demand Capacity Resource, the Capacity Supply Obligation associated with any Energy Efficiency measures shall be excluded from the calculation of the resource's Capacity Performance Score. The resulting Capacity Performance Score may be positive, zero, or negative.

III.15.8.2.5. Capacity Performance Payment Rate.

The Capacity Performance Payment Rate shall be ~~\$9337~~\$3500/MWh. The ISO shall review the Capacity Performance Payment Rate in the stakeholder process as needed and shall file with the Commission a new Capacity Performance Payment Rate if and as appropriate.

III.15.8.2.6. Calculation of Capacity Performance Payments.

For each resource, whether or not it has a Capacity Supply Obligation, the ISO shall calculate a Capacity Performance Payment for each five-minute interval in which a Capacity Scarcity Condition exists in the Capacity Zone in which the resource is located. A resource's Capacity Performance Payment for an interval shall equal the resource's Capacity Performance Score for the interval multiplied by the Capacity



memo

To: NEPOOL Markets Committee

From: Chris Geissler, Director, Economic Analysis

Date: May 6, 2026

Subject: Pay-for-Performance Revisions: Performance Payment Rate (WMPP ID: 191)

The ISO is requesting a vote on proposed Tariff revisions to update the Performance Payment Rate (PPR) to \$3,500/MWh.

By way of background, the Pay-for-Performance construct provides a market mechanism to incent improved investments and performance during stressed system conditions. This design was motivated by an observed reduction in resource performance over time, as the previous capacity market construct created limited incentives to perform.

The PPR represents the rate at which capacity resources are settled depending on whether they over- or under-perform during a Capacity Scarcity Condition. Stakeholders have encouraged the ISO to consider potential revisions to the PPR to address concerns with heightened financial risk for resources and impacts on consumer costs.

To address these concerns, the ISO proposes to set the PPR at \$3,500/MWh, which is a level that has been seen to incent investment and performance from prior periods, while also helping to address concerns about excessive risk associated with the current rate.¹ The ISO proposal lowers the likelihood that resources reach the monthly or annual stop loss and reduces the performance risk associated with holding a CSO, while still providing a substantial incentive to meet the original objectives of Pay-for-Performance.

The Markets Committee has reviewed the proposed change highlighted above including the Market Rule 1 language. The proposal has been presented on the meeting dates outlined below:

- March 10-12, 2026, [agenda item #03](#)
- April 14-16, 2026, [agenda item #04](#)
- May 12-14, 2026, [agenda item #04](#)

¹ ISO New England, "Performance of Capacity Resources and Pay for Performance," analysis presented at the NEPOOL Markets Committee, Westborough, MA (September 13-14, 2022), https://www.iso-ne.com/static-assets/documents/2022/09/a03_mc_2022_09_13-14_performance_of_capacity_resources_memo_rev1.pdf



Pay-For-Performance Revisions:

Proposed Change to the Performance Payment Rate (PPR)

Chris Geissler

DIRECTOR, ECONOMIC ANALYSIS



PFP Proposed Change to the Performance Payment Rate

WEPOOL PARTICIPANTS COMMITTEE
JUNE 16-18, 2026 SUMMER MEETING, AGENDA ITEM #9
Attachment B
191

Proposed Effective Date: September 1, 2026

- The Performance Payment Rate (PPR) is the \$ per MWh rate at which capacity resource overperformance and underperformance during Capacity Scarcity Conditions (CSC) is settled
- Addressing concerns that stakeholders have raised, the ISO is proposing to reduce the PPR from \$9,337 to \$3,500
- The ISO seeks a vote on its proposal at today's meeting

Primary Purpose of Pay-for-Performance

- The Pay-for-Performance construct was put into place to provide a market mechanism to incent cost-effective investments and improved performance during stressed system conditions
- This design was motivated by an observed reduction in resource performance over time, as the previous capacity market construct created limited incentives to perform



Performance Payment Rate: Background

- The PPR represents the per MWh rate at which resources are credited/charged for over/underperformance during CSCs
- The PPR has been set at various levels since PFP has been in place, ranging from \$2,000 during the first set of Capacity Commitment Periods (CCP) to \$9,337 at present
- Stakeholders have encouraged the ISO to consider potential revisions to the PPR to address concerns with financial risk for resources and impacts on consumer costs

Performance Payment Rate: Considerations

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JULY 14-15, 2016 SUMMER MEETING AGENDA ITEM #9
Attachment B

- The ISO seeks to set the rate at a level to incent investment and strong performance while accounting for the fact that a higher rate may increase the risks (performance and stop loss) and costs to selling capacity:
 - To the extent that the higher PPR leads to elevated costs/risks with little corresponding reliability benefit, this may adversely impact market outcomes
 - Could also result in resources that provide reliability value to the region choosing to exit because the performance risks are simply too great
 - Such outcomes would run counter to the aims of PFP

Performance Payment Rate: Basis for Proposal

- The ISO is proposing to update the PPR to \$3,500 based on these considerations:
 - Setting a fixed PPR will provide a degree of stability and transparency amidst the various capacity market reforms underway
 - Analysis of resource investment and performance [shared with stakeholders in 2022](#) found that the core objectives of PFP were being achieved
 - At the time of this analysis, the PPR was \$3,500, indicating that this rate (in conjunction with energy market scarcity pricing) incents strong levels of investment and resource performance, while also helping to address concerns about excessive risk associated with the current rate

REDLINE REVIEW



Proposed Changes to III.13.7.2.5

NEPOOL PARTICIPANTS COMMITTEE
JUNE 16, 2026 SUMMER MEETING, AGENDA ITEM #9
Attachment B

Section	Tariff or Manual Change	Reason for Change
III.13.7.2.5	III.13.7.2.5 Capacity Performance Payment Rate. For the three Capacity Commitment Periods beginning June 1, 2018 and ending May 31, 2021, the Capacity Performance Payment Rate shall be \$2000/MWh. For the three Capacity Commitment Periods beginning June 1, 2021 and ending May 31, 2024, the Capacity Performance Payment Rate shall be \$3500/MWh. For the Capacity Commitment Period beginning on June 1, 2024 and ending on May 31, 2025, the Capacity Performance Payment Rate shall be \$5455/MWh. For the ~~Capacity Commitment~~ <u>Period</u> beginning on June 1, 2025 and ending on ~~August~~<u>May</u> 31, 2026 ~~and thereafter~~, the Capacity Performance Payment Rate shall be \$9337/MWh. ~~Thereafter, the Capacity Performance Payment Rate shall be \$3500/MWh.~~ The ISO shall review the Capacity Performance Payment Rate in the stakeholder process as needed and shall file with the Commission a new Capacity Performance Payment Rate if and as appropriate.	Incorporation of proposed numerical adjustment

Proposed Changes to III.15

NEPOOL PARTICIPANTS COMMITTEE
JUNE 16-18, 2026 SUMMER MEETING, AGENDA ITEM #9
Attachment B

Section	Tariff or Manual Change	Reason for Change
III.15.8.2.5	III.15.8.2.5. Capacity Performance Payment Rate. The Capacity Performance Payment Rate shall be ~~\$93373500~~/MWh. The ISO shall review the Capacity Performance Payment Rate in the stakeholder process as needed and shall file with the Commission a new Capacity Performance Payment Rate if and as appropriate.	Incorporation of proposed numerical adjustment
III.15.a	are set forth in Section III.15.7. Payments and charges resulting from participation in the Annual Capacity Market, Monthly Reconfiguration Auctions, and bilateral transactions, <u>as well as Capacity Performance Payments</u>, are set forth in Section III.15.8. The publication of auction-related information is set forth in Section III.15.9.	Addition to “Annual Capacity Market Overview”
III.15.d	(d) Effectiveness for the 2028-2029 Capacity Commitment Period and Thereafter. The provisions of this Section III.15 are effective for the Capacity Commitment Period that runs from June 1, 2028 through May 31, 2029 and all Capacity Commitment Periods thereafter. Unless otherwise expressly stated, the provisions of this Section III.15 are not applicable to the Forward Capacity Market. Section III.13, addressing the administration of the Forward Capacity Market, shall continue to be effective for Capacity Commitment Periods through May 31, 2028. Unless otherwise expressly stated, the provisions of Section III.13 are not applicable to the Annual Capacity Market, Monthly Reconfiguration Auctions and monthly bilateral transactions addressed in this Section III.15 of Market Rule 1.	Punctuation

Key Takeaways

- The ISO proposes to update the PPR to \$3,500 with the aim of filing and implementing the change as soon as possible
- This proposed revision will help address stakeholder concerns related to heightened risks, which may impact capacity costs and could facilitate the exit of resources that provide reliability value



Stakeholder Schedule

NEPOOL PARTICIPANTS COMMITTEE
JUNE 16-18, 2026 SUMMER MEETING, AGENDA ITEM #9
Attachment B

Stakeholder Committee and Date	Scheduled Project Milestone
Markets Committee March 10-12, 2026	Delivery of the proposed design
Markets Committee April 14-16, 2026	Review of proposed Tariff language and any stakeholder amendments
Markets Committee May 12-14, 2026	Additional review of proposed Tariff language, any stakeholder amendments, and vote
Participants Committee June 16-18, 2026	Vote

Questions



APPENDIX



Impact of Lower PPR on Market Outcomes

ISO-NE POOL PARTICIPANTS COMMITTEE
JUNE 16/18, 2016 SUMMER MEETING AGENDA ITEM #9
Attachment B

- In response to stakeholder feedback, the ISO provides some additional thoughts on how a lower PPR could impact capacity market outcomes
- Next: Show that a lower PPR may reduce some offers and in some cases, this could reduce capacity prices
- However, in the long term, expect the market to incent the level of investment necessary to meet the region's resource adequacy criterion

Lower PPR Generally Does Not Impact Capacity Demand Curves

NEPOOL PARTICIPANTS COMMITTEE
JUNE 16-18, 2026 SUMMER MEETING, AGENDA ITEM #9
Attachment B

- Capacity demands are scaled to ensure that they pay Net CONE at Net ICR, which corresponds with the region's 1-in-10 resource adequacy criterion
- Implication: If the quantity of cleared capacity does not change with the lower PPR, the clearing price should be unchanged



Lower PPR May Reduce Capacity Offers for Some Resources

NEPOOL PARTICIPANTS COMMITTEE
JUNE 16-18, 2026 SUMMER MEETING, AGENDA ITEM #9
Attachment B

A couple of reasons for this:

- A lower PPR yields a lower common value component (CVC), since this value is proportional to the PPR
 - Resources that offer based on the CVC would likely offer at a lower price
 - However, some resources that were previously offered based on the CVC may now reflect going forward costs in their offer that are no longer fully recovered via the (lower) CVC
 - Reduced risk to capacity sellers makes costs of providing capacity lower
 - Decreased performance risk
 - Lower risk of incurring charges due to other resources stopping out

It Is Possible that Lower PPR May Reduce Capacity Clearing Prices

NEPOOL PARTICIPANTS COMMITTEE
JUNE 16-18, 2026 SUMMER MEETING, AGENDA ITEM #9
Attachment B

- The lower PPR therefore could result in lower capacity prices for two reasons
- Resources offering at the CVC that previously did not sell capacity now do sell capacity
- Resources that previously found the risk of selling capacity (and potentially of continuing to operate) too significant now choose to continue to operate and sell capacity



Capacity Market Should Continue to Specify Prices to Incent a Level of Investment to Meet the Region's Resource Adequacy Criterion

NEPOOL REGIONAL PARTICIPANTS COMMITTEE
JUNE 16-18, 2026 SUMMER MEETING, AGENDA ITEM #9
Attachment B

- In the long-term, the capacity market demand curves will continue to specify prices that incent sufficient capacity to meet the region's 0.1 LOLE
- If prices decrease in one auction, this is because the region has procured more capacity
 - We would generally expect the market to respond to such price signals where lower prices (due to more available capacity) may reduce investment in the future, helping to equilibrate prices in the long-term

To: Participants Committee

From: Jasleen Singh, Secretary, Markets Committee

Date: May 15, 2026

Subject: Actions of the Markets Committee from the May 2026 Meeting

This memo is to notify the Participants Committee (“PC”) of the following actions taken by the Markets Committee (MC) at the May 2026 MC meeting. A quorum was established.

(Agenda Item 1.A) Meeting Minutes

ACTION: APPROVED

The following motion was moved and seconded by the Markets Committee:

Resolved, that the Markets Committee approves the minutes for the April 14-16, 2026 Markets Committee meeting, April 14-16, 2026 Joint meeting of the Markets and Reliability Committees, and April 22, 2026 Joint meeting of the Reliability and Markets Committees, as circulated for the May 12-14, 2026 NEPOOL Markets Committee meeting, with such further non-substantive changes as the Chair and Vice-Chair may approve.

Based on a voice vote, the motion passed with none opposed and one abstention in the End User Sector.

(Agenda Item No. 2) – Pay-For-Performance Revisions: Balancing Ratio (FERC Order On The NEPGA Complaint (EL25-106))

ACTION: RECOMMEND SUPPORT

The following motion was moved and seconded by the Markets Committee:

Resolved, that the Markets Committee recommends the Participants Committee support ISO’s proposed Pay-For-Performance Capacity Balancing Ratio cap at 1.0 and related revisions to: Sections I.2.2., III. Table of Contents, III.1, III.13.5, Section III.13.7, Section III.15.6, and Section III.15.8, of the Transmission, Markets, and Services Tariff, as circulated for its May 12-14, 2026 meeting; together with any further changes recommended by this Committee, and such further non-substantive changes as the Chair and Vice-Chair of the Markets Committee may approve.

The motion was voted and, based on a voice vote, passed with no opposition and two abstentions (one in the End User Sector and one in the Generator Sector).

(Agenda Item No. 3) – Pay-For-Performance Revisions: Treatment of External Transactions

ACTION: RECOMMEND SUPPORT

The following motion was moved and seconded by the Markets Committee:

Resolved, that the Markets Committee recommends the Participants Committee support ISO's proposed Pay-For-Performance treatment of external transactions during Capacity Scarcity Conditions and settlement calculations and related revisions to: Section I.2.2, III. Table of Contents, Section III.13.7, III.15(a-d) and Section III.15.8, of the Transmission, Markets, and Services Tariff, as circulated for its May 12-14, 2026 meeting; together with any further changes recommended by this Committee, and such further non-substantive changes as the Chair and Vice-Chair of the Markets Committee may approve.

The motion was voted and, based on a voice vote, passed with no opposition and eleven abstentions (one in each of the Alternative Resource, End User, and Generation Sectors and eight in the Supplier Sector).

(Agenda Item No. 4.0) – Pay-For-Performance Revisions: Performance Payment Rate

The following main motion was moved and seconded by the Markets Committee:

Resolved, that the Markets Committee recommends the Participants Committee support ISO's proposed downward adjustment to the Performance Payment Rate and related revisions to: Section III.13.7, and Section III.15, of the Transmission, Markets, and Services Tariff, as circulated for its May 12-14, 2026 meeting; together with any further changes recommended by this Committee, and such further non-substantive changes as the Chair and Vice-Chair of the Markets Committee may approve.

Before the main motion could be voted, the following motion was moved and seconded by the Markets Committee to amend the main motion as follows:

(Vote 1 – Failed) Agenda Item 4.b – FirstLight Power Amendment – Effective Date Alignment with 19th Capacity Commitment Period that begins 6/1/2028

Resolved, that the main motion be amended to reflect changes to Section III.13.7.2.5, as contained in the materials provided by FirstLight Power, to align the effective date with the 19th Capacity Commitment Period that begins June 1, 2028; together with any further changes recommended by this Committee, and such further non-substantive changes as the Chair and Vice-Chair of the Markets Committee may approve.

The motion to amend was voted and, based on a roll call vote, failed to pass with a vote of 30.79% in favor. The individual Sector votes were Generation (4.76% in favor, 11.90% opposed, 0 abstentions), Transmission (0.00% in favor, 16.67% opposed, 1 abstention), Supplier (11.11% in favor, 5.56% opposed, 3 abstentions), Publicly Owned Entity (0.00% in favor, 16.67% opposed, 0 abstentions), Alternative Resources (14.92% in favor, 1.75% opposed, 3 abstentions), and End User (0.00% in favor, 16.67% opposed, 8 abstentions).

Before the main motion could be voted, the following motion was moved and seconded by the Markets Committee to amend the main motion as follows:

(Vote 2 – Failed) Agenda Item 4.c – JERA America’s Amendment – One-Time Evaluation of Alternative PPR Structure

Resolved, that the main motion be amended to reflect the addition of Section III.15.9.3, as contained in the materials provided by JERA Americas, to require the ISO to complete a one-time evaluation and present a report to the NEPOOL Markets Committee regarding whether implementation of an alternative Capacity Performance Payment Rate structure is warranted, with such evaluation and report to be completed before the commencement of the Capacity Commitment Period beginning June 1, 2028; together with any further changes recommended by this Committee, and such further non-substantive changes as the Chair and Vice-Chair of the Markets Committee may approve.

The motion to amend was voted and, based on a roll call vote, failed to pass with a vote of 52.20% in favor. The individual Sector votes were Generation (14.29% in favor, 2.38% opposed, 0 abstentions), Transmission (0.00% in favor, 16.67% opposed, 0 abstentions), Supplier (16.67% in favor, 0.00% opposed, 11 abstentions), Publicly Owned Entity (0.00% in favor, 16.67% opposed, 0 abstentions), Alternative Resources (15.69% in favor, 0.97% opposed, 3 abstentions), and End User (5.56% in favor, 11.11% opposed, 7 abstentions).

(Vote 3 – Passed) Agenda Item 4.a – ISO-NE Proposed Downward Adjustment to the Payment Performance Rate - Main Motion

ACTION: RECOMMEND SUPPORT

The main motion passed with a vote of 82.23% in favor. The individual Sector votes were Generation (11.11% in favor, 5.56% opposed, 2 abstentions), Transmission (16.67% in favor, 0.00% opposed, 1 abstention), Supplier (10.42% in favor, 6.25% opposed, 7 abstentions), Publicly Owned Entity (16.67% in favor, 0.00% opposed, 0 abstentions), Alternative Resources (10.70% in favor, 5.97% opposed, 0 abstentions), and End User (16.67% in favor, 0.00% opposed, 2 abstentions).

(Agenda Item No. 5) – NEPOOL Generation Information System (GIS) Working Group | Request for a vote on changes to designate specific GIS Certificates transfers under Section 83D

ACTION: RECOMMEND SUPPORT

The following motion was moved and seconded by the Markets Committee:

Resolved, that the Markets Committee recommends the changes to the NEPOOL Generation Information System and the Generation Information System Operating Rules proposed and discussed at this meeting, which relate to the marking of Certificates as being transferred under Section 83D of the Massachusetts Act Relative to Green Communities, with such non-material changes thereto as the Vice Chair of the Markets Committee may approve.

The motion was voted and, based on a voice vote, was approved with no opposition and two abstentions (one Supplier Sector and one in the End User Sector).

Amendment to ISO's Proposed PFP PPR Change to Assess Other Options

Presentation to NEPOOL Participants Committee



June 16, 2026



Our Proposal



- Accept the immediate change to a \$3,500 PPR and
- Request that ISO, prior to late 2027, assess the idea of a graduated PPR rate and any other proposals that might better tune PFP penalties and structure to the fundamental goals of the capacity market.
 - *If* that assessment leads to an ISO-recommended change, then there is time to bring that change to Stakeholders before the first CAR auction.
- Request that ISO, in its PPR filing letter, commit to completing the analysis described above.

Rationale for \$3,500



- ISO states concerns that, as formulated, the \$9,337 PPR adds inordinate market risk that could lead to uneconomic retirements and is higher than necessary to incent better generator performance.
 - See March 10 NMC presentation, posted at: https://www.iso-ne.com/static-assets/documents/100033/a03_mc_2026_03_10-12_pfp_revisions_ppr.pdf
- JERA agrees with ISO's assessment and supports ISO's effort to reduce PFP risk to manageable levels, including the short-term step down to \$3,500.
 - This will provide immediate relief and reduce risk to market participants.

Long-term Concern



- ISO's proposal, however, oversimplifies the matter. Left to itself, the short-term solution could have adverse market consequences:
 - The proposed \$3,500/MWH penalty rate (PPR) was never studied; it was a prior transition rate used as an interim steps to reach a final rate that was studied.
 - During PFP design, the PPR rate was linked with NetCONE and the Demand Curve in a way that the PPR's specific level was critical to proper functioning of the capacity market – including attracting new resources when resource adequacy targets were threatened.

Concern, continued



- ISO highlighted the importance of the PPR's link to the Capacity Market in a memo ([FCM Performance Incentives – Performance Payment Rate](#)) to NEPOOL dated 9/4/13.
 - ISO extensively explained why correctly setting the PPR is critical to the proper functioning of the capacity market, including its two primary goals of attracting new entry when needed and providing zero revenue for zero performance (the “money for nothing” problem.)
 - ISO informed the MC that it has done no analysis to confirm whether the new, \$3,500 PPR rate, would satisfy these goals that were, at the time, so critical, or why the original 2013 PPR justification is no longer applicable.
 - ISO also informed the MC that it did not look at other PFP reforms to address the unnecessarily high risk matters we now face.

One Possibly Better Reform



- We believe the real, truly unnecessary PFP risk is that most events that drive PFP events (and charges) ***are essentially random and have nothing to do with resource adequacy.***
 - Since PFP went live a decade ago, there have been 7 PFP/Scarcity Events. *Only one of those, June 18, 2024, was at the needle peak, and a resource adequacy issue.*
 - All others were related to other factors, like multiple unexpected trips, imports below schedules, load forecast errors, etc. They were essentially system security problems.
 - System performance (depth, duration of the event) was largely unrelated to the amount of CSO the region held (resource adequacy); it was more a function of RT reserves and other operational issues (system security).

One Possibly Better Reform, continued



- It is these, essentially random, often shoulder season events, that add huge amounts of unnecessary risk to generators; risk that is outside their control to manage.
 - There is little to nothing most generators can do to mitigate this risk; ***no amount of investment*** can make a generator on planned maintenance or constrained off due to transmission outages produce MWs or start a 3-hour unit in time to meet a 30-minute scarcity event, during light load.
 - There is no insurance product out there to cover many of these risks.
 - Since investment cannot mitigate these costs, the costs represent essentially pure risk. The only way for the generator to hedge exposure is to bid higher, put money away “just in case,” and then spend it when necessary.
 - This is not good for generators or load.

Possible Reform – Graduated PPR



- Benefits of a graduated PPR rate:
 - Increase PPR rate during true resource adequacy events.
 - Generators can plan for these events and make investments for the units to be more reliable. Load benefits from a more reliable system following those investments.
 - Low PPR rate(s) during security-related events.
 - Penalizing during these random events sends no signal to invest (because that investment would not mitigate risk); instead, static PPR rates at current levels either drive higher bid prices or drive otherwise economic generators into premature retirement. Load sees no benefit – it only pays higher risk premiums.
 - Rates and triggers could be set to meet the critical PFP goals discussed in ISO's 2013 memo, as well as avoid the unnecessary market risks cited by ISO in its March 2026 presentation to the MC.

PPR Amendment FirstLight

NEPOOL Participants
Committee
June 2026



Amendment would make PPR change effective at the start of CCP 19

Background & Proposed Amendment

- The ISO-NE proposes to reduce the Performance Payment Rate (PPR) from \$9,337 to \$3,500, effective September 1, 2026.
- FirstLight seeks to amend the effective date of the ISO-NE proposed PPR change to June 1, 2028, the start of the delivery period for Capacity Commitment Period 19.

Summary of Key Points

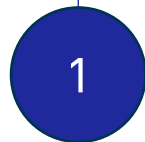
- The PPR is part of a two-settlement system; changing the second step of the settlement after the first step has been determined is inappropriate. This would be akin to modifying the calculation of the real-time energy price for tomorrow after the day-ahead energy market had cleared.
- The Monthly Stop Loss and Annual Stop Loss rates are based on the Forward Capacity Auction Starting Price which is based on the Cost of New Entry (CONE) and the Net Cost of New Entry (Net CONE), which calculation relied on the existing PPR.
- The earlier ISO-NE effective date hinges on a reliability concern that has not been identified.



The PPR is the common rate to both parts of the same FCM transaction

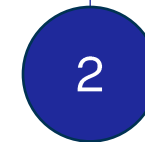
First Forward Capacity Market (FCM) Settlement Step

- The ISO-NE sets the PPR, which is used to calculate Net CONE. Net CONE determines the shape of the MRI demand curve used in the Forward Capacity Auction (FCA). For CCP 17 and CCP 18, the PPR used to calculate Net CONE was \$9,337/MWh.
- Capacity sellers use the PPR information to determine the minimum level compensation needed to take on the forward Pay-for-Performance (PFP) financial obligation, which absent sufficient physical performance, is an agreement to buyback any under-performance at the PPR.
- The base capacity price is cleared in the FCA against the MRI demand curve (which is a function of the PPR).



Second FCM Settlement Step

- Capacity sellers are required to provide a minimum amount of performance as energy or operating reserve during a scarcity event. If they under-perform their PFP obligation, they buyback that portion of their performance obligation at the PPR.
- Resources providing more performance than their forward performance obligation are paid for that over-performance at the PPR.



Changing the PPR affects multiple FCM rates



“ISO-NE notes that the Capacity Performance Payment Rate is directly affected by changes to the CONE value and ISO-NE’s estimate of net EAS revenues, while the Capacity Performance Payment Rate is itself an input to the Net CONE value. Thus, ISO-NE argues, changing the inputs to, and outputs from, the Capacity Performance Payment Rate, while not also updating the rate itself, would result in an incongruous set of partially updated auction parameters”

*Order Accepting, in Part, Tariff Revisions, Subject to Condition and Directing Compliance Filing
Docket No. ER21-787-001 (May 28, 2021), at par.142*

Both the PFP Monthly Stop Loss (MSL) and the Annual Stop Loss (ASL) mechanisms rely on the FCA Starting Price, which is based on the value of CONE and Net CONE (which is based on the level of PPR):

- $ASL = MaxCSO \times [3 \text{ months} \times (FCA_{cp} - FCA_{sp}) - (12 \text{ months} \times FCA_{cp})]$ ¹
where $FCA_{sp} = Max[1.6 * Net \text{ CONE}, CONE]$ ²
- MSL “...will be limited to an amount equal to the product of the applicable Forward Capacity Auction Starting Price multiplied by the resource’s Capacity Supply Obligation for the Obligation Month...”³

Consequently, the PPR needs to remain consistent with the value used to calculate Net CONE for the Commitment Period



The ISO-NE proposal hinges on an undisclosed reliability need

- At the NEPOOL Markets Committee, ISO-NE opposed the FirstLight Amendment on the grounds that failing to lower the PPR during CCP 17 and CCP 18 would risk exit by some resource or class(es) of resources that are needed for reliability.
- Even after highlighting that the tariff provides the ISO-NE with the authority to reject any reconfiguration auction requests to shed a CSO that would either worsen local transmission reliability or region-wide operable capacity adequacy, the ISO-NE has still not identified the nature of the *different* reliability need.



*“Supply offers in reconfiguration auctions shall be reviewed by the ISO to ensure the regional and local adequacy achieved through the Forward Capacity Auction and other reliability needs are maintained. ... **The ISO shall reject supply offers that would otherwise clear in a reconfiguration auction that will result in a violation of any NERC or NPCC criteria, or ISO New England System Rules** during the Capacity Commitment Period associated with the reconfiguration auction. The ISO’s reliability reviews will assess such offers, beginning with the marginal resource, **based on operable capacity needs ...and will include transmission security studies.** Supply offers that cannot meet the applicable reliability needs will be rejected in their entirety and the resource will not be rejected in part. Rejected resources will not be further included in clearing the reconfiguration auction...”*

Market Rule 1, Section III.13.4.2.1.5

How can this new reliability need not be specifically identified when the ISO-NE’s September 1, 2026 effective date hinges on that need?



MEMORANDUM

TO: NEPOOL Participants Committee Members and Alternates

FROM: Rosendo Garza, NEPOOL Counsel

DATE: June 9, 2026

RE: Adjustments to the Day-Ahead Ancillary Services Market

At its June 16, 2026 Summer Meeting, the Participants Committee will be asked to support the ISO's proposal to revise Market Rule 1 to implement targeted post-implementation adjustments to the Day-Ahead Ancillary Services (DAAS) market design (DAAS Proposal). This memorandum provides background, summarizes the DAAS Proposal and stakeholder process to date, and includes the following attachments:

- Attachment A: Market Rule 1 Redline Sheets
- Attachment B: ISO-NE's April 14–16, 2026 Markets Committee Presentation
- Attachment C: ISO-NE's May 12–14, 2026 Markets Committee Presentation
- Attachment D: Markets Committee Notice of Actions, dated June 9, 2026
- Attachment E: FirstLight's June 9–11, 2026 Markets Committee Presentation

BACKGROUND

The DAAS market has been in place since March 2025. Through that market, the ISO procures reserve products and physical energy needed to support the next-day operating plan.

Following the first year of DAAS market operation, the ISO's Internal Market Monitor (IMM) recommended a limited set of refinements.¹ The IMM's recommendations focused on three inputs to the market design: the Strike Price, the Forecast Energy Requirement (FER) Demand Quantity, and the non-performance factor (NPF) used in reserve requirement calculations. In general terms, the IMM recommended raising the Strike Price to better reflect the costs of resources providing DAAS, lowering the FER Demand Quantity to account for the expected contribution of renewable generation, and reassessing the NPF.

The ISO agreed that targeted changes were appropriate. The NPF change has already been addressed operationally. Following Reliability Committee review, the ISO reduced the NPF from 120% to 115% beginning with the May 1, 2026 Operating Day.² The DAAS Proposal to be considered at the Summer Meeting concern Tariff revisions to the Strike Price, the related

¹ Memorandum from David Naughton, Executive Director, Internal Market Monitor, ISO New England Inc. to the NEPOOL Markets Committee 1 (Feb. 4, 2026), https://www.iso-ne.com/static-assets/documents/100032/a03_mc_2026_02_10-11_imm_recommendations_potential_daas_improvements.pdf.

² See ISO New England Inc., *Day-Ahead Ancillary Services Post-Implementation Adjustments*, at 6 (Apr. 22, 2026), https://www.iso-ne.com/static-assets/documents/100034/a05_reserve_nonperformance_factor_updates.pdf.

mitigation threshold, the FER Demand Quantity, and a separate Day-Ahead Net Commitment Period Compensation (DA NCPC) clean-up for import transactions.

ISO-NE's DAAS PROPOSAL

As further described in the background material included with this memorandum, the ISO's DAAS proposal has three principal components, plus one related clean-up item.

First, the ISO proposes adding a floor to the DAAS Strike Price. The floor would be based on the marginal cost of energy from an efficient distillate-fired combustion turbine, using regional emissions costs and the lowest-priced available distillate fuel.

Second, the ISO proposes a corresponding change to the DAAS Impact Test Threshold. The ISO proposes to establish a \$3/MWh floor for that threshold. According to the ISO, this adjustment is intended to avoid making the mitigation test more restrictive in low-closeout hours where market power concerns are not likely to be significant.

Third, the ISO proposes to reduce the FER Demand Quantity to account for forecasted front-of-the-meter wind and solar output better. The proposed change would reduce the FER Demand Quantity by the amount of forecasted front-of-the-meter wind and solar output that is not otherwise expected to clear as Day-Ahead energy or Ancillary Services.

Finally, the ISO proposes a DA NCPC change for Day-Ahead import transactions. The proposed Tariff revision would count the FER price in the hourly revenue calculation for DA NCPC purposes regardless of FER Credit eligibility, thereby preventing an ineligible import from receiving the FER value through uplift.

The ISO is targeting implementation of the DAAS Proposal on October 22, 2026, for the clearing of the October 23, 2026 Operating Day.

The complete set of proposed Tariff redlines are included as Attachment A.

STAKEHOLDER PROCESS TO DATE

The ISO presented the DAAS Proposal to the Markets Committee over three meetings. In April, the ISO introduced the proposed adjustments and explained how they were responsive to the IMM's recommendations. In May, the ISO provided estimated market impacts and initial Tariff language. At its June 9–11, 2026 meeting, the Markets Committee considered a FirstLight amendment (described immediately below) and the ISO's unamended Proposal. FirstLight's amendment received a 20.83% Vote in favor.³ The ISO's unamended proposal was supported by the Markets Committee, with a 64.54% Vote in favor.⁴

³ Markets Committee Notice of Actions, Attachment C, at 2.

⁴ *Id.*

FirstLight Amendment. As further described in Attachment E, FirstLight proposed an amendment that would remove the Strike Price floor from the ISO’s package of DAAS revisions. FirstLight’s amendment would have restored the currently effective Tariff language in Section III.1.8.2⁵. More information about the FirstLight Amendment, including FirstLight’s rationale for its proposal is provided in its presentation to the Markets Committee, which is included with this memorandum. FirstLight has indicated that it intends to seek a Participants Committee vote on its Amendment.

PLANNED PROCESS FOR PARTICIPANTS COMMITTEE ACTION

The following form of resolution may be used for Participants Committee action:

RESOLVED, that the Participants Committee supports ISO-NE’s DAAS Proposal and related revisions to Market Rule 1 of the Transmission, Markets, and Services Tariff, as recommended by the Markets Committee at its June 2026 meeting, together with [any changes agreed to by the Participants Committee at this meeting and] such non-substantive changes as may be approved by the Chair and Vice-Chair of the Markets Committee.

⁵ In response to feedback ISO-NE provided during the June 2026 Markets Committee meeting, FirstLight modified the proposal reflected in Attachment E. Specifically, FirstLight withdrew its proposed revisions to Tariff Section III.A.8.1.2. *See also* Attachment C, at 2 (specifying, in the motion to amend, FirstLight’s proposed Tariff changes to the ISO’s proposal).

I. Draft Tariff Redlines for Proposed Adjustment to the Strike Price

III.1.8.2 Day-Ahead Ancillary Services Strike Price.

(a) For each hour of the Operating Day, the ISO shall specify the Day-Ahead Ancillary Services Strike Price in \$/MWh. The value of the Day-Ahead Ancillary Services Strike Price represents an amount that is the greater of the values calculated in accordance with subsections (1) and (2) below:

(1) the greater of (i) \$10/MWh greater than a forecast of the expected hourly Real-Time Hub Price for such hour of the Operating Day and (ii) zero; and

(2) a floor value derived in accordance with subsection (c) below.

(b) The ~~forecast used to determine the Day-Ahead Ancillary Services Strike Price value calculated in subsection (a)(1) above~~ shall be based on a publicly-available forecasting algorithm developed by the ISO. The ISO shall describe the publicly available forecasting algorithm to Market Participants and shall periodically review and assess the efficacy of the forecasting algorithm. The ISO shall notify stakeholders of any potential revisions to the ISO's forecasting algorithm prior to implementing such revisions.

~~(c) In the event that the ISO is not able to utilize the ISO-developed forecasting algorithm described in subsection (b) above due to hardware, software, or telecommunications problems, human error, or exigent circumstances not contemplated by this market rule, the ISO shall determine the Day-Ahead Ancillary Services Strike Price using the best forecast available and shall disclose the use of such substitute forecast to Market Participants as soon as practicable.~~

(c) The floor value in subsection (a)(2) above shall be determined daily based on the marginal cost of supplying energy by an efficient, distillate-fired combustion turbine generator, reflecting regional emissions costs and the lowest-priced distillate fuel available. The ISO shall describe to Market Participants the heat rate, emissions cost, and fuel prices that it uses to determine the value in subsection (a)(2).

(d) In the event that the ISO is not able to utilize the methods in subsections (a) through (c) above due to hardware, software, or telecommunications problems, human error, or exigent circumstances not contemplated by this market rule, the ISO shall determine the Day-Ahead Ancillary Services Strike Price using the best forecast and floor value available and shall disclose the use of such substitute method to Market Participants as soon as practicable.

III.A.8.1.2. Impact Test.

A Day-Ahead Ancillary Services Offer with a price that fails the conduct test for Day-Ahead Ancillary Services Offer mitigation shall be evaluated against the impact test for Day-Ahead Ancillary Services Offer mitigation. A Day-Ahead Ancillary Services Offer fails the impact test for Day-Ahead Ancillary Services Offer mitigation if there is an increase in any Day-Ahead Price, as calculated pursuant to

Sections III.A.8.3 or III.A.8.4, in any hour of the Operating Day and such increase is ~~greater~~ higher than the greater of (a) \$3/MWh and (b) 150% of the median difference between:

- (i) the threshold prices for failing the conduct test described in Section III.A.8.1.1 for all Day-Ahead Ancillary Services Offers in the hour of the Operating Day being evaluated; and
- (ii) the Day-Ahead Ancillary Services Benchmark Levels as described in Section III.A.8.2 for all Day-Ahead Ancillary Services Offers in the hour of the Operating Day being evaluated.

II. Draft Tariff Redlines for Proposed Adjustment to the FER

III.1.8.4 Forecast Energy Requirement Demand Quantity. For each hour of the Operating Day, the Forecast Energy Requirement Demand Quantity shall be: ~~equal to~~

(1) the ISO forecast for the total load in the New England Control Area produced pursuant to Section III.1.10.1A(h) of this Market Rule 1, less

(2) the greater of (i) the forecast of front-of-the-meter dispatchable wind and solar resources' total real-time energy supply, as adjusted for any expected operating conditions, less the total energy supply and ancillary services from such resources forecast to clear in the Day-Ahead Market and (ii) zero.

III. Draft Tariff Redlines for Proposed Adjustment to NCPC

III.F.2.3.1.3. Hourly Revenue. The Day-Ahead revenue for a pool-scheduled External Transaction import at an External Node for an hour is equal to the cleared Day-Ahead transaction amount (MW) for the hour multiplied by the Day-Ahead Price, where the Day-Ahead Price is equal to the Day-Ahead Locational Marginal Price plus the Forecast Energy Requirement Price, ~~not~~ subject to the credit conditions specified in Section III.3.2.1(q)(4)(ii). For Increment Offers at an External Node, the Day-Ahead revenue at an External Node for an hour is equal to the cleared Day-Ahead transaction amount (MW) for the hour multiplied by the Day-Ahead Locational Marginal Price.

III.3.2.1(q)(4) * * *

Forecast Energy Requirement Credit for External Transaction Purchases – Each Market Participant with an External Transaction purchase scheduled in the Day-Ahead Energy Market for which a corresponding External Transaction also has been properly submitted in the Real-Time Energy Market and submitted in the appropriate external Control Area shall be credited the Forecast Energy Requirement Price, calculated in accordance with Section III.2.6.2(b), for the lesser of (a) each MWh of the Day-Ahead energy obligation associated

with the External Transaction and (b) each MWh offered for the corresponding External Transaction in the Real-Time Energy Market.



memo

To: NEPOOL Markets Committee

From: Benjamin Ewing, Technical Manager – Market Development

Date: June 3, 2026

Subject: Day-Ahead Ancillary Services Post Implementation Adjustments (WMPP ID: 192)

The ISO is requesting a vote on proposed Tariff revisions that make targeted changes to adjust the Day-Ahead Ancillary Services (DA A/S) Market in response to recommendations from the ISO's Internal Market Monitor (IMM).

By way of background, in February 2026 the IMM recommended incremental design adjustments to improve the cost effectiveness of the DA A/S market, based upon its observations and analysis of the first year of the market's operation.¹ The ISO reviewed and agreed with the recommendations, and proposed targeted updates to the non-performance factor (NPF), adding a floor to the strike price based upon indicative characteristics of a distillate-fired combustion turbine (CT), and adjusting the Forecast Energy Requirement (FER) Demand Quantity.

The reduction to the NPF from 120% to 115% was reviewed and discussed by the Reliability Committee on April 22, 2026 and put into effect on April 30, 2026 for the May 1, 2026 Operating Day. Given the improvements in resource performance and additional market and operational changes that incentivize and support resource responsiveness, a reduction to the NPF better aligns reserve requirements with demonstrated system needs without compromising reliability.

The proposed strike price floor better aligns the strike price with the short run marginal costs of the class of resources observed to have cleared a significant share of DA A/S awards. This proposal balances tradeoffs by reducing the range between short run marginal costs and the strike price (in which such resources would not physically cover their position), reducing closeout cost risk while preserving incentives when system conditions are tightest. The ISO also proposes to implement a floor of \$3/MWh on the Impact Test Threshold, to address the potential for over-mitigation in hours when expected closeout is very low, and market power is not a significant concern.

The ISO proposes reducing FER Demand Quantity by the forecasted but uncleared real-time front-of-the-meter wind and solar generation to avoid over-procurement and better align the Day-Ahead Market with the Reserve Adequacy Analysis process, the ISO's longstanding reliability evaluation.

¹ See Internal Market Monitor's Recommended Changes to the Day-Ahead Ancillary Services Market (February 4, 2026) https://www.iso-ne.com/static-assets/documents/100032/a03_mc_2026_02_10-11_imm_recommendations_potential_daas_improvements.pdf

Finally, the ISO proposes to include the FER price in Hourly Revenue calculations for Day-Ahead Net Commitment Period Compensation (DA NCPC) calculations for all day-ahead cleared imports. This proposed change will prevent imports that are not eligible to receive the FER price (as a result of not submitting a corresponding real-time transaction) from receiving that price through DA NCPC credits.

The Markets Committee has reviewed the proposal, including Market Rule 1 language including changes to Appendix A and F. The ISO targets implementation on October 22, 2026.

The proposal has been presented on the meeting dates outlined below:

- Markets Committee: April 14-16, 2026 [agenda item #02](#)
- Reliability Committee: April 22, 2026 [agenda item #05](#)
- Markets Committee: May 12-14, 2026, [agenda item #06](#)

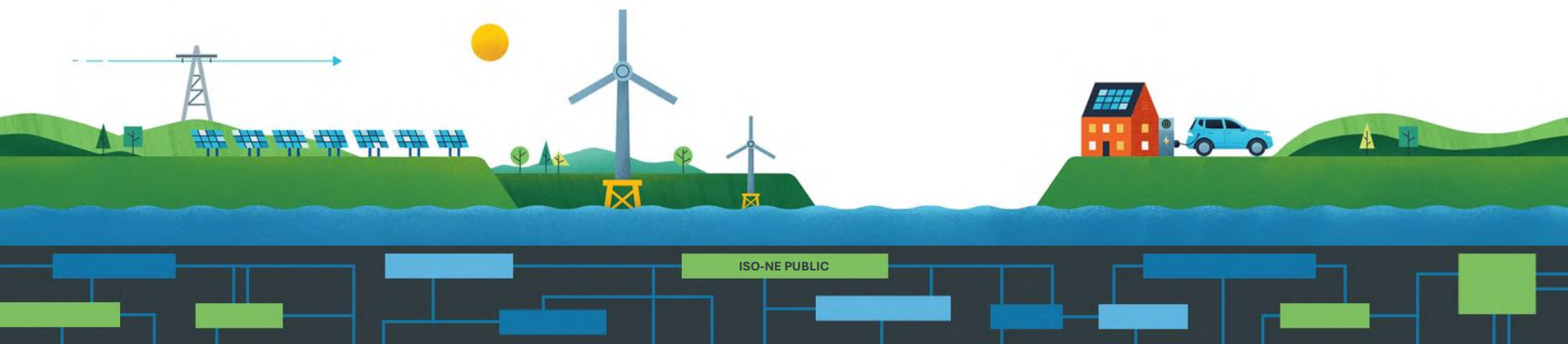
Day-Ahead Ancillary Services Post-Implementation Adjustments



*Targeted changes to the DA A/S design
based on IMM recommendations*

Ben Ewing

TECHNICAL MANAGER



Day-Ahead Ancillary Services Post-Implementation Adjustments

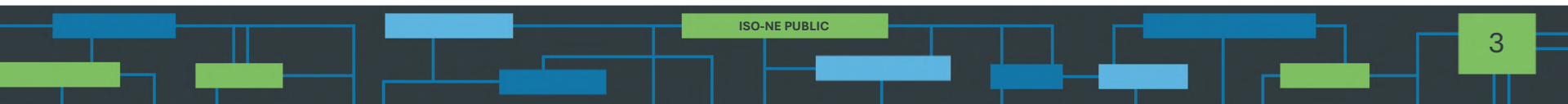
WMPP ID
192

Proposed Effective Date: Early Q4 2026 (targeting implementation on 10/22/26 for clearing of 10/23/26)

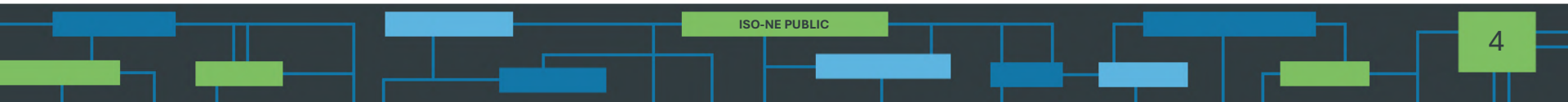
- In February 2026, the ISO's Internal Market Monitor (IMM) issued a set of [DA A/S recommendations](#), with two goals:
 - Enhance the cost-effectiveness of the market design based on observations over first year of operation
 - Cost effectiveness may be enhanced by addressing inefficiencies observed in the market design which may result in higher-than-necessary costs
 - Maintain the core DA A/S design principles of transparently procuring, pricing, and compensating the services required for a secure DA operating plan
- The IMM's recommendations were targeted at three specific inputs to the DAM with the intent of making changes straightforward to implement: the Forecast Energy Requirement (FER) Demand Quantity (DQ), the Non-Performance Factor (NPF) applied in 10- and 30-minute reserve requirements, and the Strike Price (K)
- The ISO has reviewed the reviewed IMM's recommendations and is generally supportive. The ISO's proposed adjustments are consistent with the recommendations and market design objectives
- In addition, the ISO is proposing a clean-up item related to Day-Ahead Net Commitment Period Compensation (DA NCPC)
- Today's discussion will focus on the ISO's considerations for evaluating design adjustments and introduce the proposed adjustments to the FER DQ and Strike Price as well as the DA NCPC clean-up item
 - The proposed NPF adjustment will be discussed at the April Reliability Committee meeting and Markets Committee members are encouraged to attend
 - At the May MC, the ISO plans to share simulations to backcast estimated cost impacts of the proposed changes

ISO Considerations When Evaluating Design Adjustments

1. Maintain core DA A/S objectives of transparently procuring and pricing the reliability attributes associated with a secure day-ahead operating plan, while maintaining performance incentives when they are most important
2. Reduce or eliminate inefficiencies associated with the existing design that may contribute to unnecessary costs
3. Ensure ability to implement changes quickly
4. Strike an appropriate balance between performance incentives, reducing inefficiencies, and implementation speed while recognizing that no solution will be perfect but that directional improvements are possible

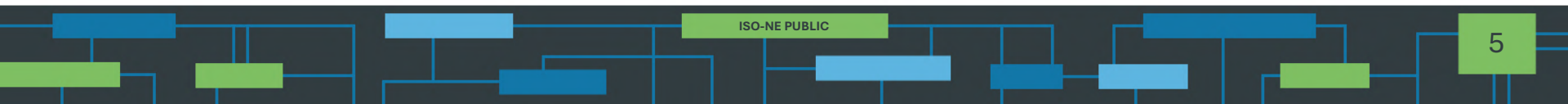


FORECAST ENERGY REQUIREMENT DEMAND QUANTITY ADJUSTMENT



IMM Recommendation – FER DQ

- IMM recommends a downward adjustment to the Forecast Energy Requirement Demand Quantity to fully reflect the expected reliability contribution of front-of-the-meter wind and solar generators (FtM W/S)
- Such an adjustment is intended to:
 - Align treatment of FtM W/S in the DAM's FER constraint with the treatment of these resources in the ISO's day-ahead reliability assessment, the Reserve Adequacy Analysis (RAA) process
 - Align treatment of FtM W/S with that of BtM W/S
- ISO agrees with this recommendation
 - Adjustment to the FER DQ will help address the potential for procuring more supply than necessary to satisfy reliability needs, improving market efficiency
- *Next*, we'll provide some background on DAM and RAA processes, and how FtM W/S are considered in them

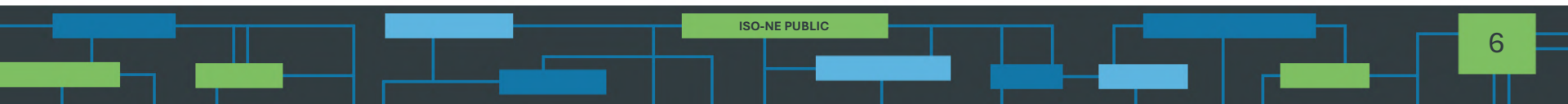


DAM and FER Background

- The FER constraint reflects the reliability need to satisfy the day-ahead load forecast within the clearing of the DAM, and transparently prices that need
 - In doing so, the FER constraint reflects a component of the ISO's out-of-market Reserve Adequacy Analysis (RAA) process through a market construct
- The FER constraint is constructed as follows:

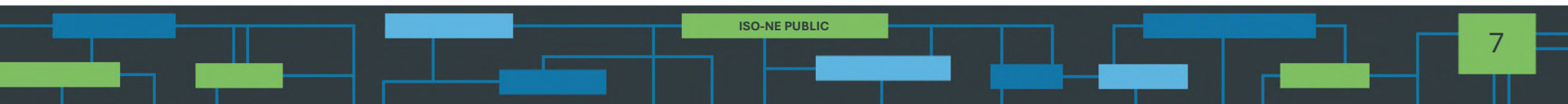
$$\text{Generator}_{\text{DA Energy}} + \text{Import}_{\text{DA Energy}} + \text{EIR} \geq \text{FER DQ} + \text{Export}_{\text{DA Energy}}$$

- Today, FER DQ is set equal to the load forecast, which reflects the physical energy supply the ISO expects to need to meet next-day energy demand
 - Energy and EIR awards cleared on all front-of-the-meter (FtM) resources (including wind and solar), serve to meet this demand (*more on why this matters in a moment*)
- Expected output of behind-the-meter (BtM) generation (i.e., solar) is fully accounted for in the DAM by reducing the load forecast. Illustrative example:
 - Gross New England Load = 12,500 MW
 - Expected BtM generation = 500 MW
 - Load Forecast = 12,000 MW



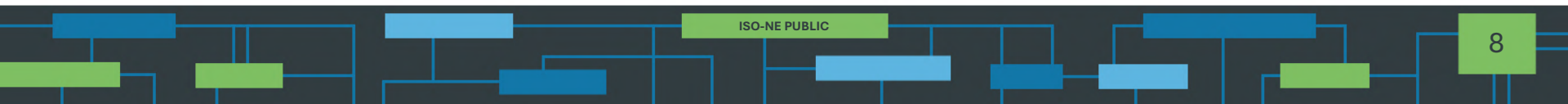
RAA Process Background

- After the DAM runs, the Reserve Adequacy Analysis process takes the DAM solution and evaluates its ability to meet forecasted load and reserve requirements
 - This is the ISO's reliability assessment
- RAA process considers all DAM committed and fast-start generation using real-time supply offers
- Generally, this means that when assessing reliability the RAA process counts on FtM W/S to operate at MWh levels equal to the ISO's resource-specific forecast of energy output
 - RT supply offers are typically $\leq \$0/\text{MWh}$
 - Binding transmission constraints can cause RAA to count FtM Renewables at less than forecast

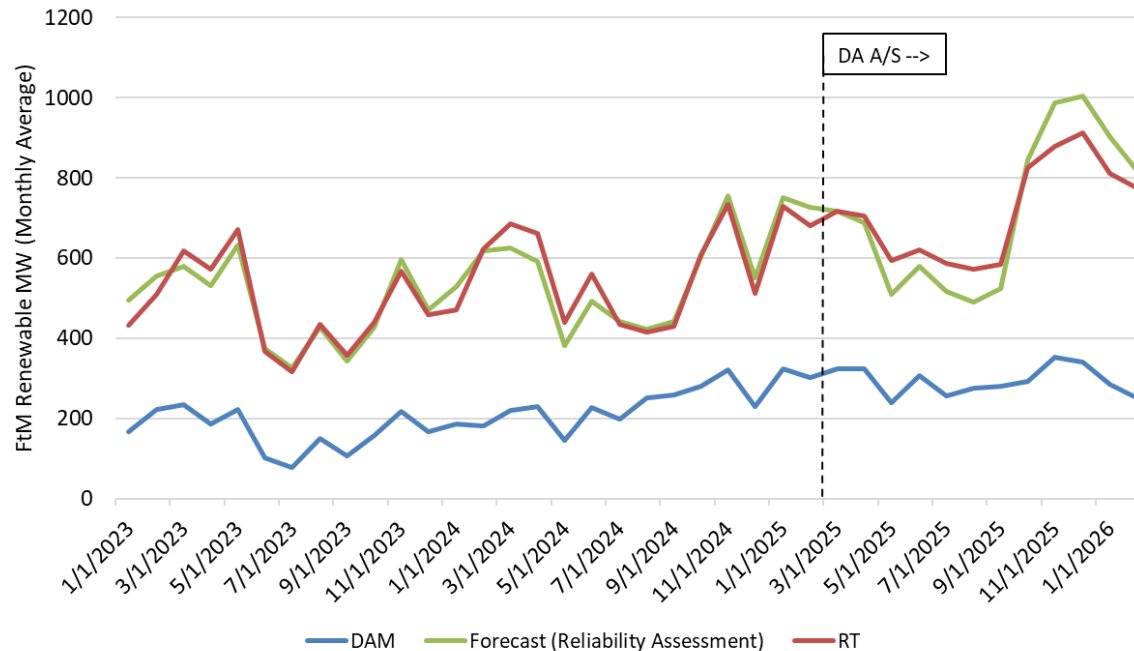


DAM vs RAA - FtM Wind/Solar Accounting

- **DAM:** FtM W/S often offer a portion of their capability at a low price, and the remainder of their capability at a higher price
 - In doing so, resources with CSO satisfy the ‘must offer’ requirement, but clear energy below their forecast
 - As a result, FtM W/S typically contribute less energy than their forecast to the FER constraint
- **RAA:** FtM W/S generally counted toward system needs at ISO’s forecast of their real-time output
 - This tends to be greater than DA cleared quantities
- This means that the FER undercounts FtM W/S contributions relative to the RAA process, the ISO’s standard reliability assessment
 - As a result, the DAM may commit additional resources or clear other forms of supply in place of FtM W/S to meet the load forecast
- Procuring more supply than is needed to satisfy a reliability requirement can be costly and inefficient



FER vs RAA - FtM Wind/Solar Accounting (*cont'd*)



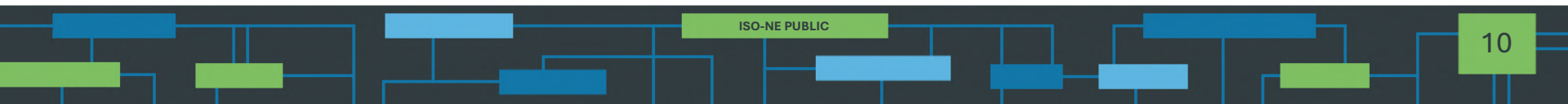
- Varies month-to-month, but on average FtM W/S clear ~40% of forecast in DAM
- This share has not increased with DA A/S implementation

FER Demand Quantity Adjustment Proposal

- ISO proposes to adjust the FER Demand Quantity (currently set equal to the ISO's load forecast) down by the expected amount of forecasted but uncleared real-time FtM W/S generation

$$\text{Proposed FER DQ} = \text{Load Forecast} - \max(\text{FtM W/S Forecast} - \text{Expected FtM W/S Cleared Energy and EIR}, 0)$$

- This approach has a number of desirable properties:
 - It directly addresses the inefficiency observed by the IMM by better aligning treatment of FtM W/S in the FER constraint with the treatment of FtM W/S in the ISO's reliability assessments; 'extra' supply will not be committed or cleared to satisfy load forecast
 - It aligns FtM W/S treatment with BtM W/S treatment in that the forecasted output of each is fully counted at forecasted value in the DAM
 - It will 'automatically' adjust as FtM renewable offer behavior changes in the future; as these resources clear more energy, the size of the adjustment will shrink
 - FtM renewable resources will continue to be paid the FER Price for the energy and EIR that they do clear in the DAM
 - It can be implemented relatively quickly



FER Demand Quantity Adjustment Impact

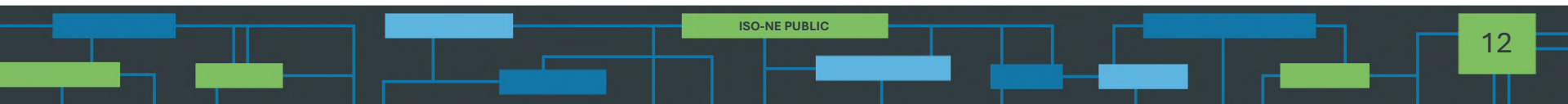
Statistic	FER DQ Adjustment MW (FtM RAA MW - FtM DA Clear MW)
25th percentile	162
Median	370
Average	422
75th Percentile	607
95th Percentile	1,039

- On average, proposal would reduce the ISO's load forecast by ~422 MW when calculating the FER DQ that serves as an input to the DAM
- FER DQ adjustment is 0 MW in ~3% of hours
- Estimates of cost impacts to come in May

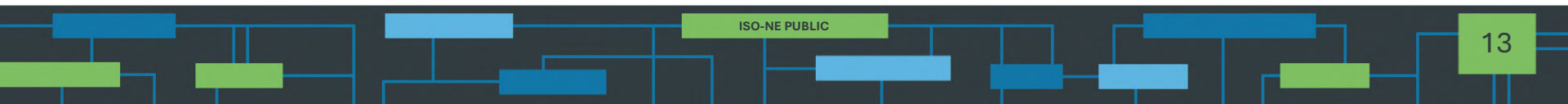
Data Timeframe:
Mar 2025 - Feb 2026

FER DQ Adjustment – Key Takeaways

- Currently, the FER constraint in the DAM tends to count on less FtM W/S supply than the ISO's day-ahead reliability evaluation in the RAA process
- This results in a market inefficiency, in that the DAM may commit additional generation and/or procure more physical supply than necessary to satisfy the load forecast
- The ISO proposes to adjust the FER DQ down in a manner that accounts for this discrepancy, improving alignment of the FER and ISO reliability assessments and reducing this inefficiency



STRIKE PRICE ADJUSTMENT

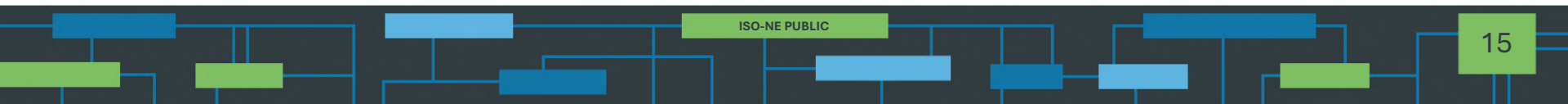


IMM Recommendation – Strike Price

- IMM recommends an upward adjustment to the Strike Price (K) to better align it with the short-run marginal cost (SRMC) of DA A/S providers
 - Specifically, IMM recommends consideration of dynamically applying a floor to K based on the SRMC of a combustion turbine (CT)
- **Objective:** Better align K with the SRMC of resources observed to be clearing most DA A/S awards
 - Setting K ‘too low’ for DA A/S sellers provides limited incremental reliability value but additional closeout cost risk, as resources will not physically cover obligation when RT LMP falls above K but below SRMC (IMM memo, p. 6)
 - This may contribute to higher DA A/S offer prices, or lack of DA A/S participation
- IMM acknowledges that changes to K require a ‘balancing act’
 - Setting K ‘too low’ may increase offer prices and decrease participation
 - Setting K ‘too high’ will reduce performance incentives

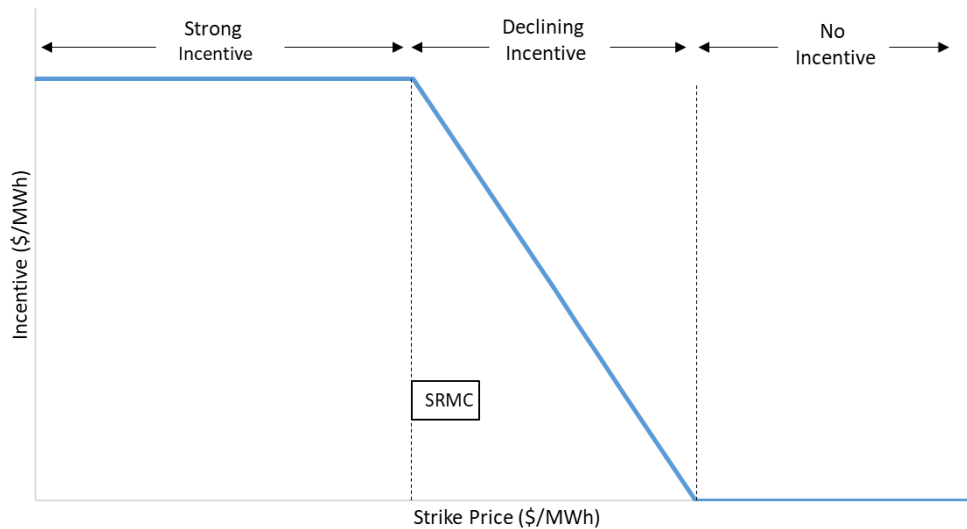
ISO Perspective – Strike Price Recommendation

- ISO acknowledges IMM's observations and objective
 - CTs have cleared a majority of DA A/S awards to date, though many other resource types also contribute
 - Setting K far below SRMC for resources does not improve their incentives, but does increase closeout-related risk
 - Participation may increase with a higher K and a lower risk of closeout
- ISO supports applying a floor to K
 - An approach that applies a floor based upon simple logic will be straightforward to implement
- Any approach to adjusting K comes with tradeoffs, and there is no perfect solution given (1) heterogeneity of DA A/S suppliers' technologies and energy costs and (2) the uniform, system-wide hourly value for K
 - As K is adjusted upward and becomes better aligned with the SRMC of one class of resources, it may exceed the SRMC of other resources and thereby reduce their performance incentives
- *Next, we'll discuss ISO's considerations related to this balancing act*



Strike Price and Incentives

- The incentives provided by the DA A/S design reflect the difference in a seller's expected net revenue if its resource is able to operate in RT, relative to its expected net revenue if its resource is not able to operate in RT
- Incentives are efficient when $K \leq \text{SRMC}$, and declining when $K > \text{SRMC}$
 - As K exceeds MC, incentives decline because the difference in closeout charges between the 'can operate' and 'cannot operate' scenarios decreases (toward zero)
 - See [November 2022 DASI presentation](#) for detailed discussion (begin slide 49)



- Our evaluation of incentives therefore considers whether K exceeds the SRMC of each seller of DA A/S
 - If $K \leq \text{SRMC}$, incentives are fully retained
 - If $K > \text{SRMC}$, incentives are not fully retained

DA A/S Seller Characteristics

- DA A/S sellers are predominantly Combustion Turbine (CT) and Combined Cycle (CC) resources, with CTs clearing the majority of DA A/S awards

Asset Type	DA A/S Cleared GWh	Percent DA A/S Awards Cleared	Percent FRS Awards Cleared	Percent EIR Awards Cleared	Full Load Average Heat Rate (MMBtu/MWh)
CT	13,600	64.7%	64.3%	71.6%	12
CC	6,041	28.7%	29.1%	21.1%	8
Other	1,387	6.6%	6.6%	7.3%	<i>n/a</i>

- Heat rates for CCs fall within a relatively tight band, while heat rates for CT have more variability

Type	Full Load Average Heat Rate Statistics					
	10th Pctl	25th Pctl	Median	Average	75th Pctl	90th Pctl
CC	7	7	7	8	7	9
CT	9	10	11	12	14	15

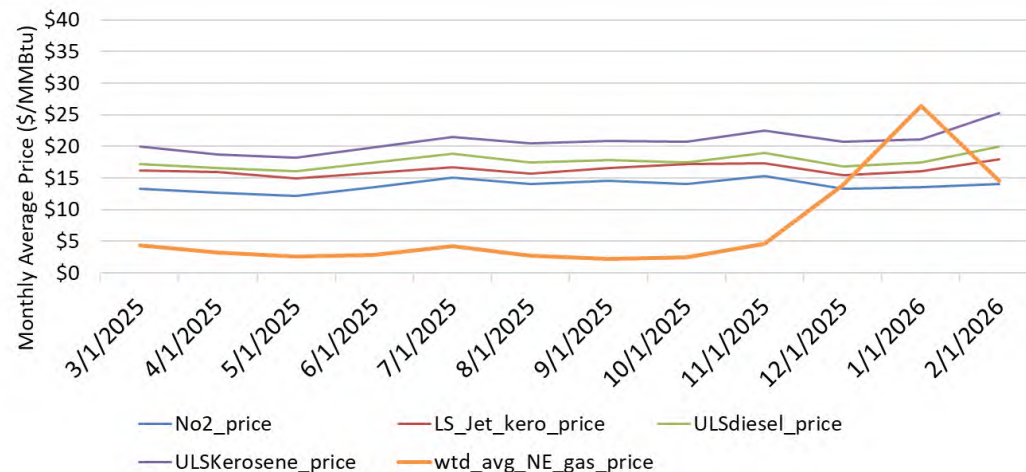
Data Timeframe:
Mar 2025 - Feb 2026

DA A/S Seller Characteristics (cont'd)

- While CCs generally operate on natural gas, there is more variability in fuel types across the CT fleet

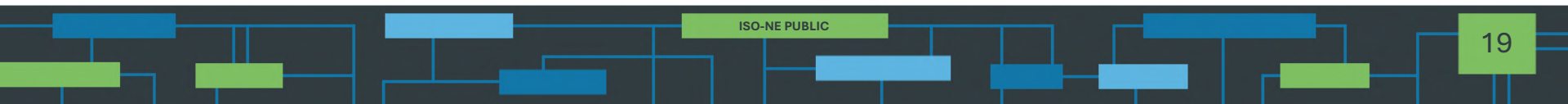
CT - Fuel	DA A/S Cleared GWh	Percent DA A/S Awards Cleared on CTs
Oil - ULSKerosene	6,478	48%
Natural Gas	3,491	26%
Oil - Diesel	2,016	15%
Oil - No2	1,144	8%
Oil - LS Jet Kero	470	3%

- Distillate fuel prices were stable during the past year, but differ by fuel



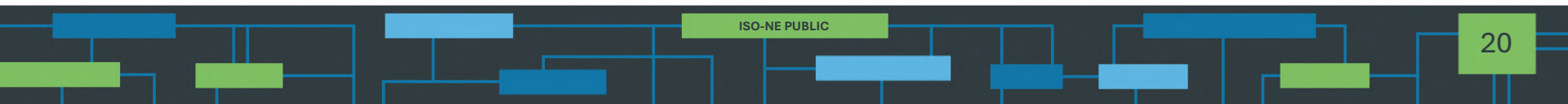
ISO Proposal Overview

- ISO proposes to use indicative characteristics of CTs to tailor a floor for the strike price
 - Consistent with IMM recommendation (p. 5-7)
- In doing so, we seek to balance three goals:
 - Increase strike price to be better aligned with the SRMC of most sellers of DA A/S
 - Reduce incentives the least (for all DA A/S sellers) in hours when reliability risk is highest
 - Allow for quick implementation
- ISO will continue to evaluate GMM for ways to improve its performance
 - Implementation of floor on the strike price does not imply that such work would end



ISO Proposal Overview (*cont'd*)

- Proposed floor on the strike price is based on characteristics of an efficient CT using the lowest-cost distillate fuel
- Using efficient CT characteristics will help ensure $K \leq \text{SRMC}$ of the oil-fired offline fast-start fleet, which the system relies upon to respond to challenging and/or unanticipated reliability conditions
 - These resources clear a significant share of DA A/S awards (winter and summer)
- This will reduce incentives for some sellers clearing DA A/S on gas-fired resources (primarily CCs), which will often have $\text{SRMC} < K$ under this proposal
 - However, analysis indicates that this proposed approach to a strike price floor will minimally reduce incentives for the resources clearing DA A/S during highest load conditions (in summer), and during highest fuel-price conditions (in winter) (*more on this ahead*)



Proposed Strike Price Floor

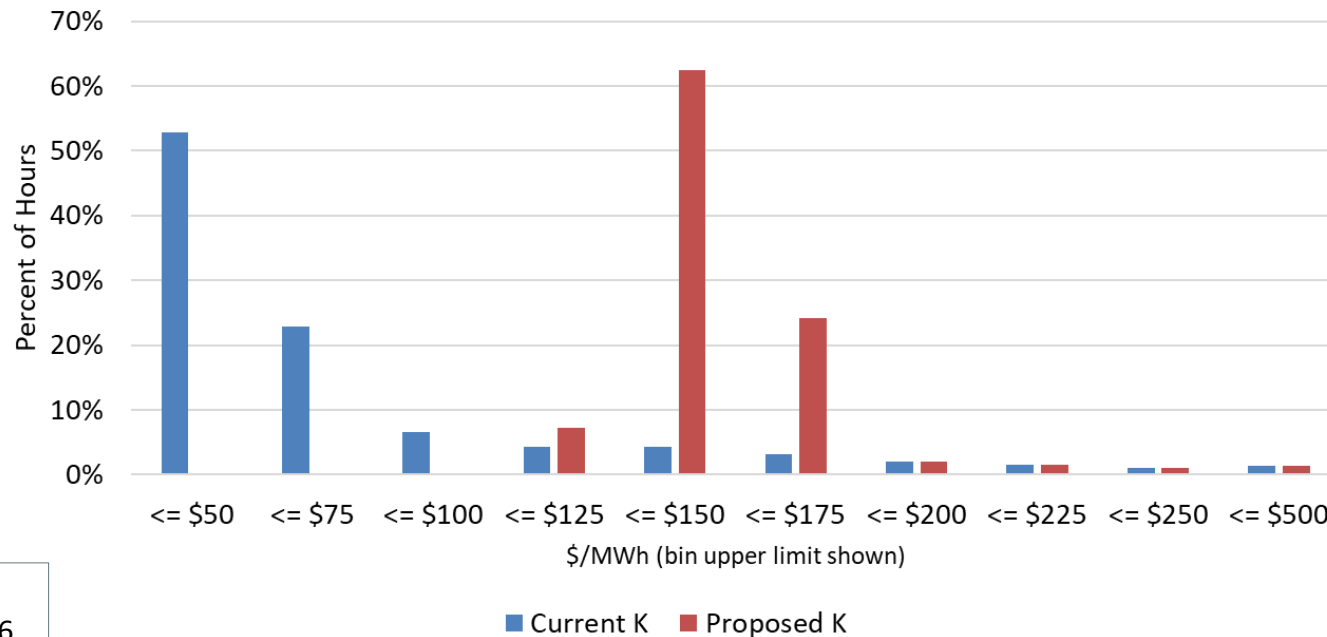
- Heat Rate of an efficient CT
 - Propose to use 9 MMBtu/MWh in implementation
- Fuel-Related Costs
 - Use the lowest cost of the four distillate fuels used by CTs observed to clear DA A/S
 - Costs reflect both fuel price and emissions costs (in \$/MMBtu)
 - Natural gas is not considered (*More on this in later slides*)
 - These fuels are ULS Kerosene, ULSD Diesel, LSJ Kerosene, and No2 Oil
 - Generally, No2 Oil has the lowest cost historically

$$K_{\text{floor}} = 9 \text{ MMBtu/MWh} \times \text{Min}(\text{ULSK}_{\text{cost}}, \text{ULSD}_{\text{cost}}, \text{LSJK}_{\text{cost}}, \text{No2}_{\text{cost}})$$

- Proposed $K = \text{Max}(K_{\text{floor}}, E[\text{RT LMP}] + \$10)$
 - Note the \$10 adder is still proposed to be reflected in the strike price (*More on this in later slides*)
- By selecting an efficient heat rate and low-cost fuel, we increase the strike price to a level conceptually aligned with the SRMC of CTs
 - However, incentives will be impacted for some DA A/S sellers (*More on this later slides*)

Effect on Strike Price

- Proposed average K_{floor} = \$141/MWh, and the floor results in a higher strike price in ~90% of hours
- GMM sets the strike price in ~10% of hours
- Strike price, with floor applied, falls in \$110-\$175/MWh range in 94% of hours



Data Timeframe:
Mar 2025 - Feb 2026

Effect on Incentives by Load Forecast

- DA A/S seller's incentives are considered 'fully retained' if proposed K falls below the SRMC of energy blocks cleared for DA A/S
 - Floor is most impactful in low-load hours, with a 41-47% decrease in the MWh of DA A/S awards that fully retain the current DA A/S design's incentives
 - Floor is less impactful in high-load hours, with only a 12-16% decrease in the MWh of DA A/S awards fully retaining incentives
 - Median [SRMC – K] delta decreases across all hours, but particularly low-load hours
- Takeaway:** smaller reductions in incentives in high-load hours indicates proposal strikes a reasonable balance between increasing K and retaining incentives at times when they are needed most

Percentile of Load Forecast Bin	Stats Across Hours when K changes			Percent Decrease in DA A/S awards fully retaining Incentives	Median Hourly Delta (SRMC - K _{Curr}) (\$/MWh)	Median Hourly Delta (SRMC - K _{Prop}) (\$/MWh)
	% Hours K changes	Avg K _{Curr} (\$/MWh)	Avg K _{Prop} (\$/MWh)			
0 - 25th	100%	\$36	\$137	-47%	\$115	\$11
25 - 50th	100%	\$49	\$141	-41%	\$122	\$29
50 - 75th	95%	\$65	\$142	-30%	\$121	\$41
75 - 90th	70%	\$81	\$145	-19%	\$113	\$64
90 - 95th	42%	\$75	\$147	-12%	\$105	\$66
95 - 100th	62%	\$84	\$147	-16%	\$102	\$45

Data Timeframe:
Mar 2025 - Feb 2026

Effect on Incentives by Gas Price

- Floor is most impactful in hours with low gas prices
 - 41-43% decrease in the MWh of DA A/S awards that fully retain the current DA A/S design's incentives
- Floor is less impactful in hours with high gas prices, setting K in few hours and maintaining incentives in-line with existing design
- Median [SRMC – K] delta decreases across all hours, but particularly hours with low gas prices

Percentile of Natural Gas Price Bin	Stats Across Hours when K changes			Percent Decrease in DA A/S awards fully retaining Incentives	Median Hourly Delta (SRMC - K _{Curr}) (\$/MWh)	Median Hourly Delta (SRMC - K _{Prop}) (\$/MWh)
	% Hours K changes	Avg K _{Curr} (\$/MWh)	Avg K _{Prop} (\$/MWh)			
0 - 25th	100%	\$37	\$139	-43%	\$117	\$15
25 - 50th	100%	\$46	\$140	-41%	\$122	\$27
50 - 75th	100%	\$59	\$143	-38%	\$119	\$34
75 - 90th	83%	\$92	\$143	-23%	\$107	\$64
90 - 95th	31%	\$129	\$143	-1%	\$86	\$81
95 - 100th	3%	\$132	\$145	0%	\$134	\$132

- Takeaway:** smaller reductions in incentives in hours with high gas prices indicates proposal strikes a reasonable balance between increasing K and maintaining incentives when needed most

Effect on Incentives by Asset Type

- CCs have the largest decrease in incentives from the proposal, while CTs have the smallest
- Spreads between SRMC and K are significantly reduced by proposal

Type	% Decrease in DA A/S awards fully retaining Incentives	Median Spread (SRMC - K _{Curr}) (\$/MWh)	Spread (SRMC - K _{Prop}) percentiles (\$/MWh)			
			25th	50th	75th	90th
All Days						
CC	-79%	\$31	-\$78	-\$56	-\$31	\$37
CT	-17%	\$154	\$55	\$70	\$89	\$107
Other	-36%	\$174	\$28	\$103	\$267	\$344
15 Tight Summer Days						
CC	-82%	\$33	-\$64	-\$43	-\$28	-\$9
CT	-16%	\$146	\$50	\$64	\$78	\$88
Other	-28%	\$111	\$12	\$40	\$56	\$85
15 Tight Winter Days						
CC	0%	\$113	\$55	\$113	\$222	\$448
CT	0%	\$127	\$104	\$127	\$153	\$188
Other	0%	\$227	\$147	\$227	\$331	\$497

Data Timeframe:
Mar 2025 - Feb 2026

- Proposal is impactful on 15 selected 'tight' summer days
- Proposal has **no impact** on 15 selected 'tight' winter days
 - With high gas prices, K from the GMM exceeds the proposed floor
- Takeaway:** GMM continues to play an important role in setting K when the strike price it calculates exceeds floor

The ISO proposes to retain the \$10/MWh adder

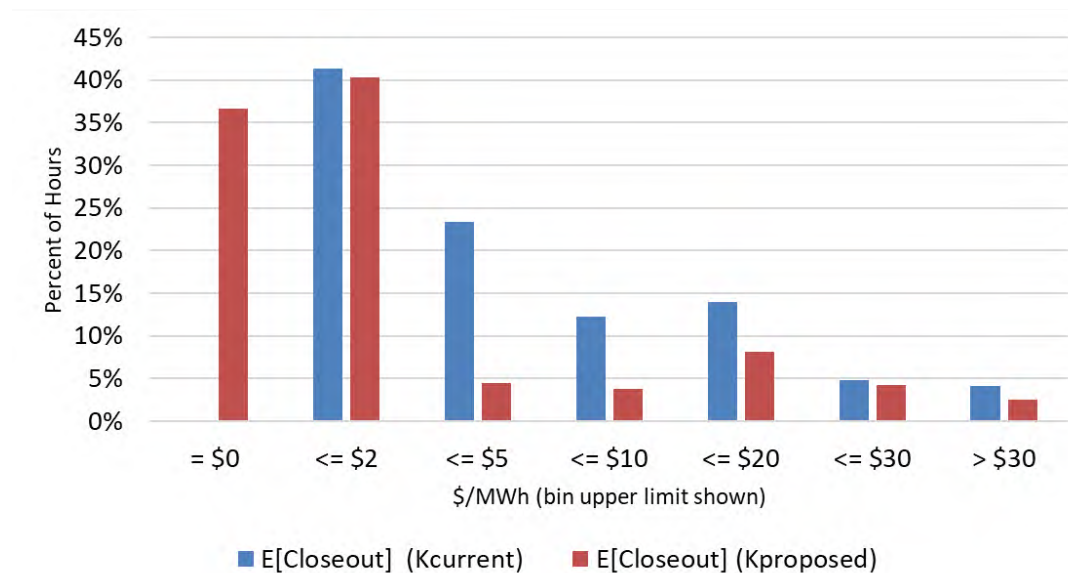
- Proposed strike price floor affects K in 90% of hours (obviating the adder), and has no effect on K in the other 10% of hours
- In this other 10% of hours, expected system conditions were sufficiently tight that $E[RT\ LMP] + \$10$ exceeded the proposed floor for K
 - This includes all hours during the extended cold period between January 25 and February 8, a notably high-cost time period
- Eliminating the \$10 adder would serve to reduce the value of K during this set of hours, when energy prices are expected to be high
 - During such high-load, high-priced hours, the adder's impact on incentives is minimal
 - See [April 2023](#) MC presentation, slide 9
- ISO does not intend to reduce the value of K in any hour as part of this set of proposed changes

The ISO proposal doesn't reflect natural gas prices in the floor

- Combined Cycles, and some CTs, offer on natural gas and clear a notable share of DA A/S awards
- In assessing approaches for applying a floor for K, use of the prevailing natural gas price was considered
 - For instance, we considered using the lesser of gas and oil prices
- Generally, we found that inclusion of natural gas prices in the floor for K had minimal impact on K, or on the difference between K and SRMC for many DA A/S sellers
 - This is an expected outcome, as gas prices are an important input when the GMM's determination of the strike price under current rules
- An approach that reflects gas prices, or representative characteristics of gas-fired generation, would not materially impact DA A/S market outcomes

Effect on Expected Closeout

- Under proposal, $E[\text{Closeout}]$ will be determined using the 'new' K , reflecting application of the floor
 - Lower $E[\text{Closeout}]$ values reflect the decreased likelihood of a non-zero closeout charge when the floor is applied to the strike price
- Proposal will reduce competitive costs associated with DA A/S awards, and would be expected to reduce DA A/S offer prices



DA A/S Mitigation Considerations

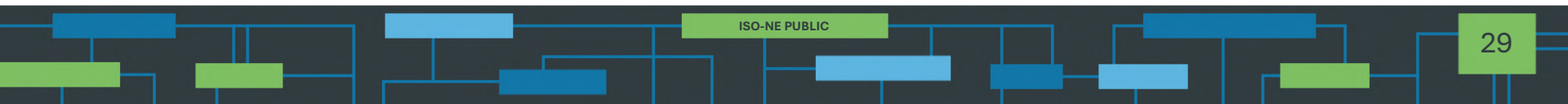
- Expected Closeout is a key component of competitive DA A/S offer prices, and factors directly into the Benchmark Level (BL), Conduct Test Threshold (CTT), and Impact Test Threshold (ITT) parameters used in mitigation

Benchmark Level = $E[\text{Closeout}] + \text{Avoidable Input Cost (AIC)}$

CTT = $\text{Max}(\$2, 2 \times E[\text{Closeout}]) + 1.5 \times \text{AIC}$

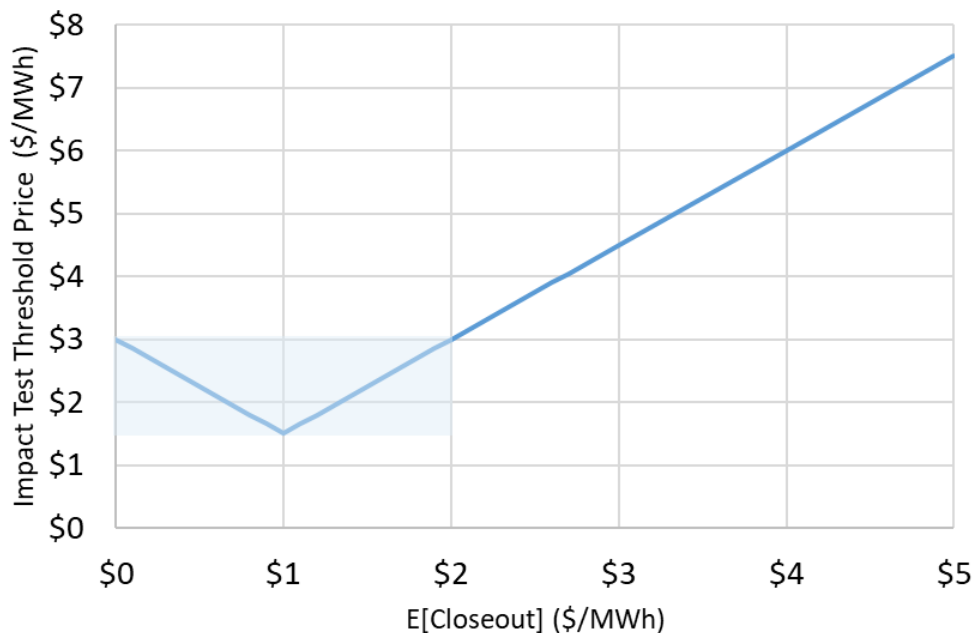
ITT = $1.5 \times \text{Median}[\text{CTT} - \text{BL}]$

- Greater frequency of hours with low $E[\text{Closeout}]$ values may result in more frequent violations of the impact test in low-priced hours when market power is not a significant concern
- The ISO proposes a targeted revision to the ITT calculation to address this issue
- This proposal aligns with External Market Monitor feedback in their [2024 Assessment of ISO-NE Electricity Markets](#) (recommendation 2024-2)



DA A/S Mitigation Considerations (*cont'd*)

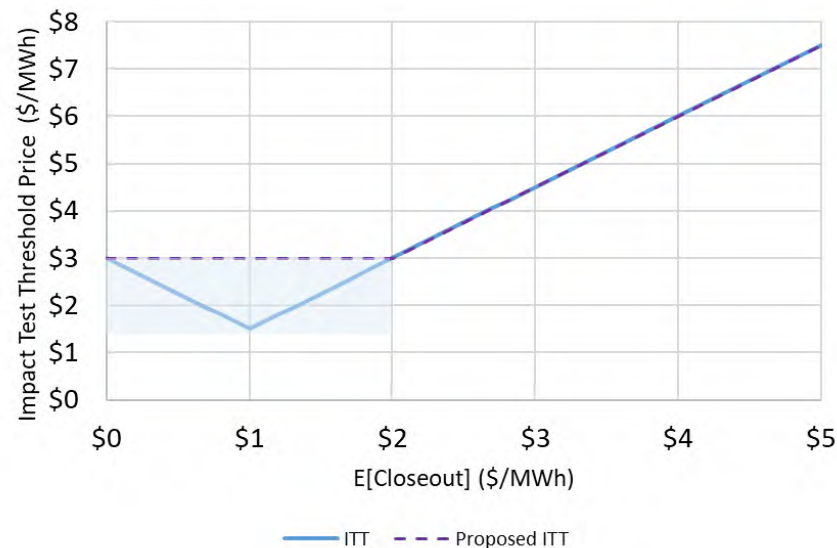
- Under the current design, the ITT initially becomes more stringent as $E[\text{Closeout}]$ increases from $\$0/\text{MWh}$ (illustrative example below)
 - This is an effect of the $\$2$ CTT floor
 - When $E[\text{Closeout}] = \$0$, the ITT is $\$3$
 - In the range $\$0 < E[\text{Closeout}] < \$2$, the ITT can be less than $\$3$, and as low as $\$1.50/\text{MWh}$



- This property of the ITT calculation was not intended
 - As competitive costs (i.e., $E[\text{Closeout}]$) increase, the acceptable change in clearing prices (i.e., the ITT) should not decrease
- With proposed floor for K , $E[\text{Closeout}]$ values may fall within this problematic range more frequently

Proposed Change to Impact Test Threshold

- ISO proposes to set a floor for the ITT at \$3/MWh
 - This will prevent the ITT from becoming more stringent when $E[\text{Closeout}]$ exceeds \$0 than it is when $E[\text{Closeout}] = \$0$
- This targeted change is intended to address the potential for over-mitigation in hours when the expected closeout is very low, and market power is not a significant concern (see EMM Assessment, p. 39)
 - This could become more prevalent with the proposed floor for K

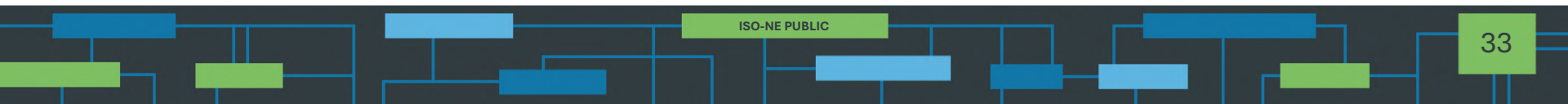


Expected Effect of Floor on Costs – Initial Qualitative Considerations

- Proposal may affect three key factors that impact consumer costs
 - **(1) DA A/S Offer Prices** are expected to decrease, resulting in lower A/S clearing prices
 - **(2) Realized Closeout Charges** are expected to decrease, resulting in smaller closeout credits to load
 - **(3) Participation** may increase, potentially putting downward pressure on A/S clearing prices
- (1) Lower clearing prices and (2) lower closeout charges will offset to some extent
- DA A/S clearing prices are a function of both offer prices and cross-product opportunity costs
 - Proposal may lead to only modest decreases in A/S clearing prices, because a higher strike price for DA A/S does not change A/S sellers' energy opportunity costs
- For purposes of estimating revenue/cost changes, assumptions will be required
 - DA A/S Offer Prices should be adjusted downward to reflect changes in expected closeouts
 - Participation changes are not possible to predict, and ISO plans to hold participation consistent with that observed historically for simulation purposes
- Estimates of cost impacts to come in May

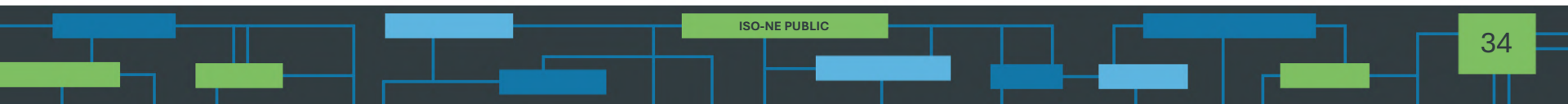
Strike Price Adjustment – Key Takeaways

- ISO proposes to set a floor for K based on representative SRMC of an efficient CT
- ISO's proposal strikes a reasonable balance between better aligning the value of K with the SRMC of a majority of DA A/S sellers, and maintaining incentives in high-load hours when they are most important
- ISO proposes an adjustment to the DA A/S Impact Test Threshold calculation to reduce the likelihood of mitigations during periods when market power is not a significant concern



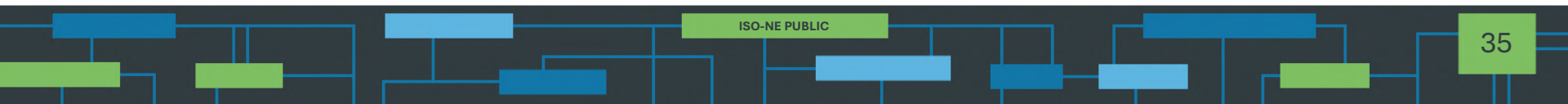
DA NCPC CLEAN-UP ITEM

Adjustment to DA NCPC Credits for Import Transactions



DA NCPC for Imports - Background

- DA cleared imports must have a corresponding RT transaction in place in order to be eligible for the FER Credit
- Currently, DA NCPC calculations consider this eligibility criteria when assessing hourly revenue
 - If a DA cleared import does not have a corresponding RT transaction, the FER price is not included in its calculation of hourly revenue
- Issue: Under current NCPC rules, DA cleared imports that are ineligible for the FER Credit can effectively receive this credit through DA NCPC payments (*more on this next*)
- This issue is infrequent, but has resulted in FER-related DA NCPC payments of ~\$73K to DA Imports ineligible for the FER Credit (Mar 2025 – Feb 2026)



DA NCPC for Imports – Illustrative Example

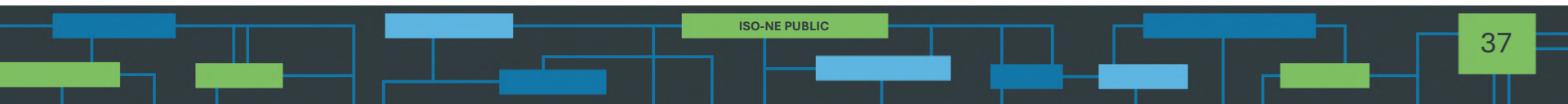
- Consider a 1 MW cleared DA Import that is on the margin for energy supply:

Concept	Value (\$/MWh)
DA Import Supply Offer	\$60
DA LMP	\$50
FER Price	\$10

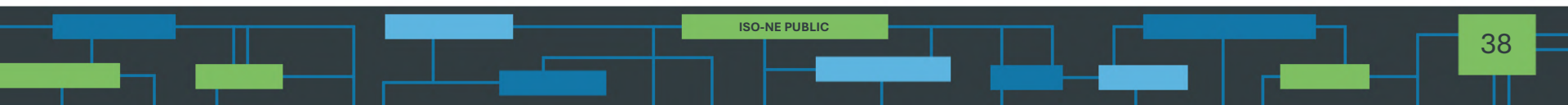
- Assume this import has no corresponding RT transaction, and is therefore ineligible for the FER Credit
- Current DA NCPC Credit Calculation:
 - Hourly Revenue = DA LMP = \$50
 - Hourly Cost = Supply offer = \$60
 - DA NCPC Credit = $\max(\text{Cost} - \text{Revenue}, 0) = \$10$
- This import effectively receives the FER price through its DA NCPC credit, despite not meeting eligibility requirements

DA NCPC for Imports – Proposal

- ISO proposes to include the FER price in DA NCPC hourly revenue calculations for Imports, regardless of FER Credit eligibility
- Proposed DA NCPC Credit Calculation:
 - Hourly Revenue = DA LMP + FER Price = \$60
 - Hourly Cost = Supply offer = \$60
 - DA NCPC Credit = $\max(\text{Cost} - \text{Revenue}, 0)$ = \$0
- This simple fix will prevent FER-ineligible imports from receiving some or all of the FER price through DA NCPC credits



NEXT STEPS AND STAKEHOLDER SCHEDULE



Conclusion and Next Steps

- ISO proposes a set of targeted changes to the DA A/S design in response to IMM's recommendations
 - FER Demand Quantity adjustment for FTM wind and solar generation (discussed today)
 - Strike Price adjustment, and corresponding change to Impact Test Threshold (discussed today)
 - Non-Performance Factor adjustment (to be discussed at April RC)
- In addition, the ISO proposes a clean-up change to DA NCPC calculations for Imports
- Next month, ISO will bring quantitative 'back-cast' calculations to estimate how these proposals might have impacted DA A/S market outcomes over the past year (had they been in effect at the time)
- Next month, ISO will bring proposed Tariff language

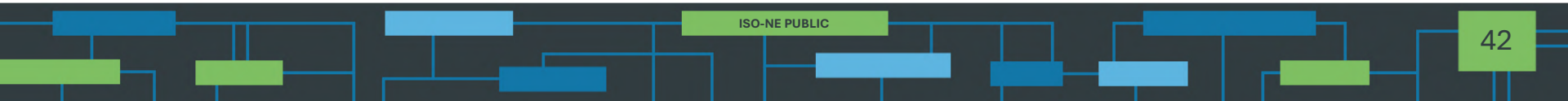
Stakeholder Schedule

Stakeholder Committee and Date	Scheduled Project Milestone
Markets Committee April 14-16, 2026	Overview of ISO proposal
Reliability Committee April 22, 2026	Review change to the Non-Performance Factor
Markets Committee May 12-14, 2026	Estimate of market impacts, initial review of proposed Tariff languages, and if applicable stakeholder amendments
Markets Committee June 9-11, 2026	Additional review of proposed Tariff language, amendments, and vote
Participants Committee June 16-18, 2026	Vote

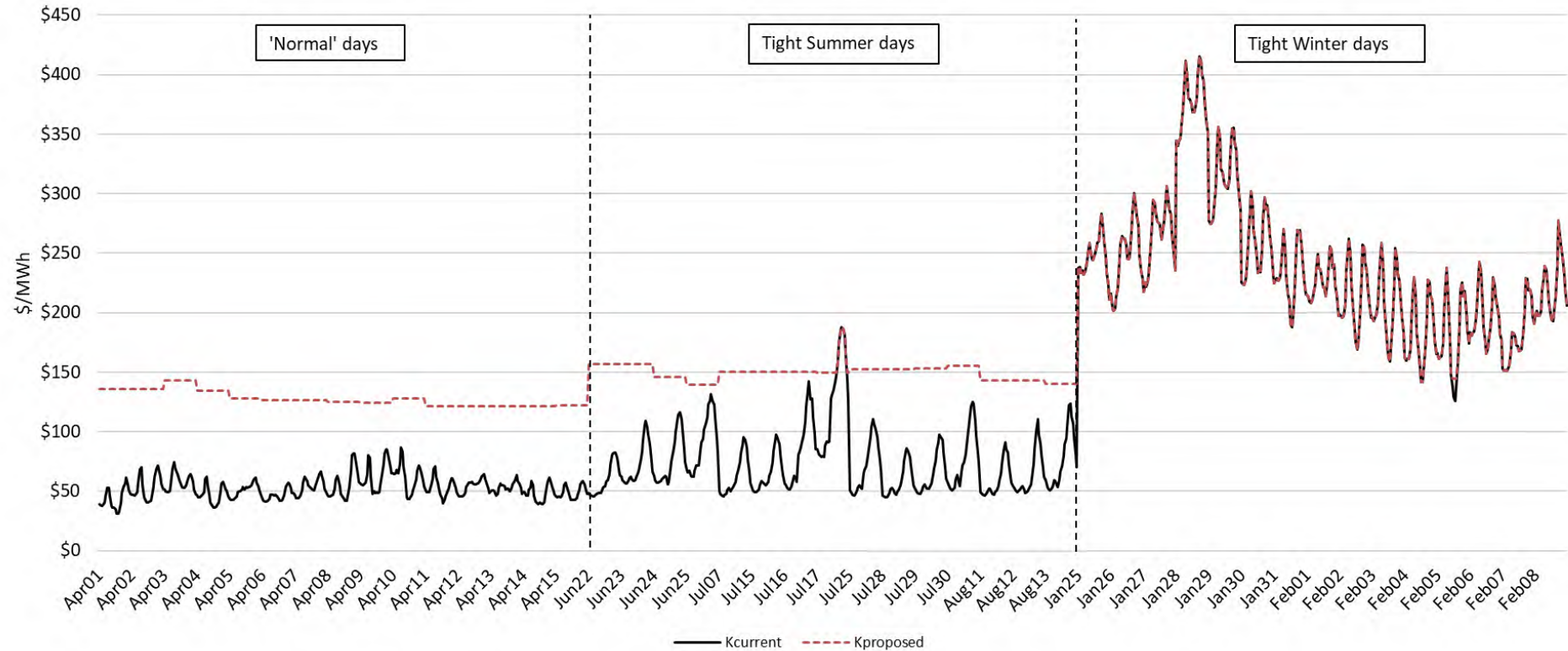
Questions



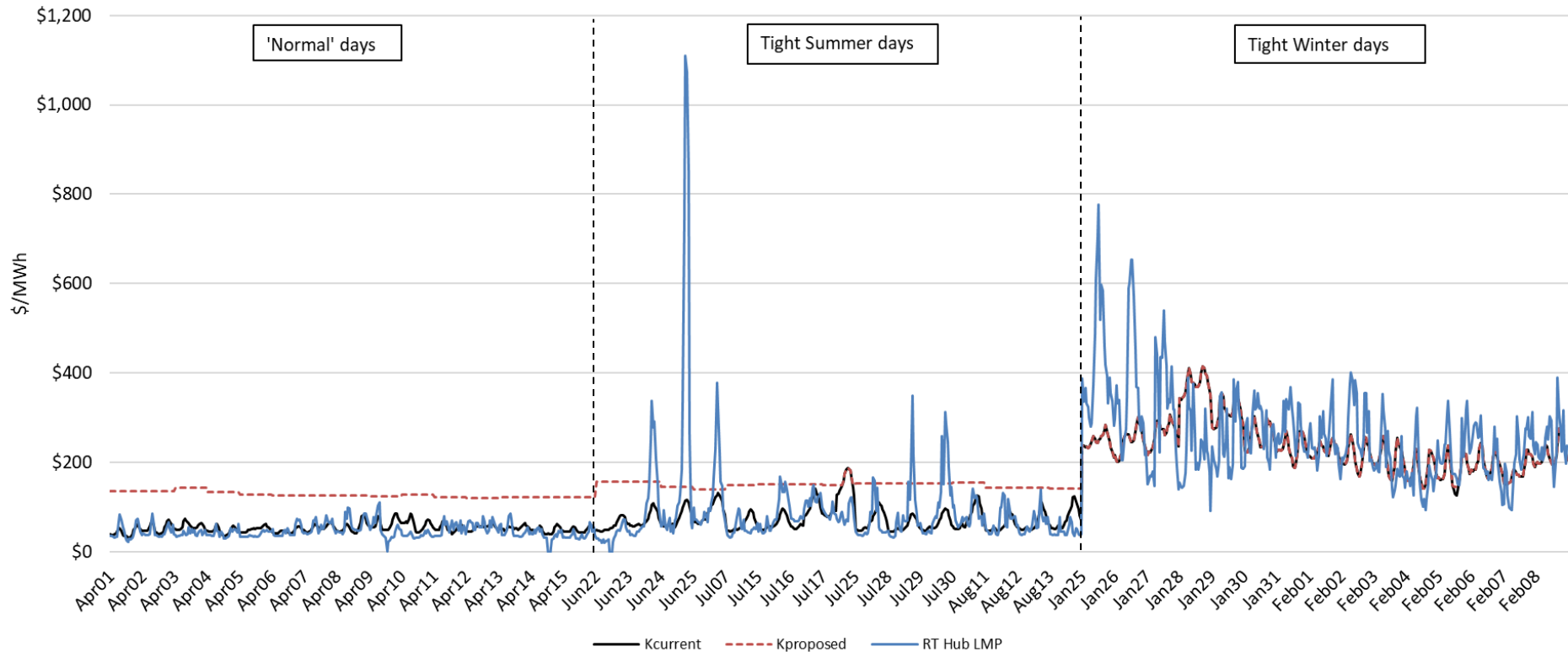
APPENDIX



Strike Price proposal on representative days



Strike Price proposal on representative days (*cont'd*)



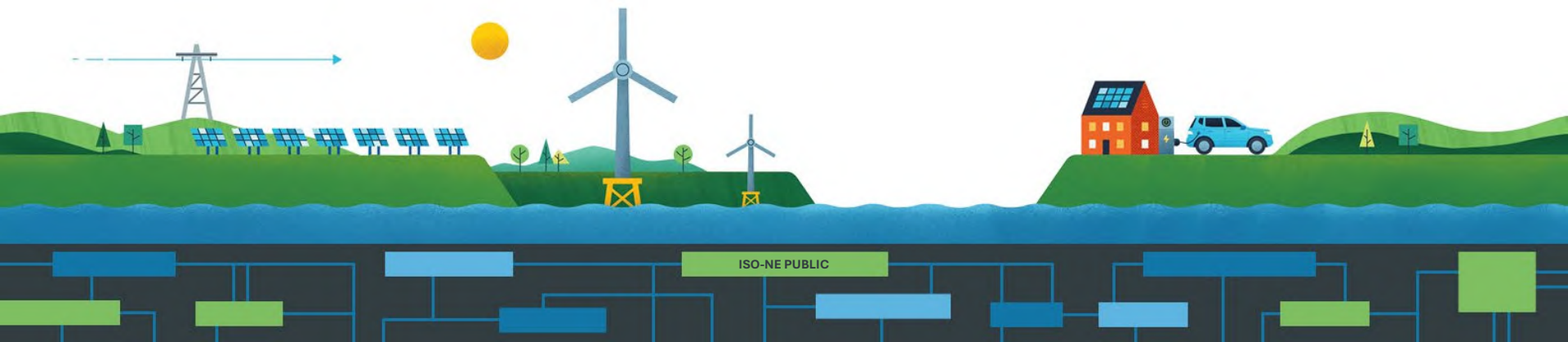
Day-Ahead Ancillary Services Post-Implementation Adjustments



*Targeted changes to the DA A/S design
based on IMM recommendations*

Ben Ewing

TECHNICAL MANAGER



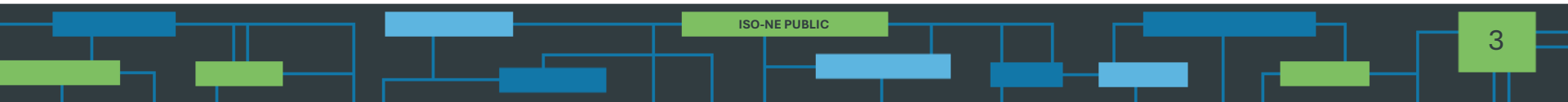
Day-Ahead Ancillary Services Post-Implementation Adjustments

WMPP ID
192

Proposed Effective Date: Early Q4 2026 (targeting implementation on 10/22/26 for clearing of 10/23/26)

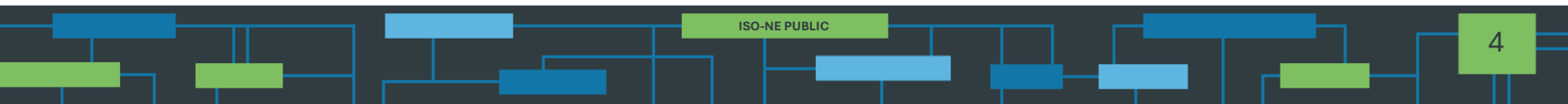
- In February 2026, the ISO's Internal Market Monitor (IMM) issued a set of [DA A/S recommendations](#), relating to three aspects of the DA A/S design:
 - Forecast Energy Requirement (FER) Demand Quantity (DQ)
 - Non-Performance Factor (NPF)
 - Strike Price (K)
- In April 2026, ISO proposed a set of changes in response to the IMM's recommendations:
 - Proposed to reduce the FER DQ by expected amount of uncleared but forecasted real-time front-of-the-meter wind and solar (FtM W/S) generation
 - Set the NPF = 115% beginning May 1, 2026
 - Proposed to set a floor for K based on indicative characteristics of an efficient, distillate-fired combustion turbine (CT)
 - Proposed floor of \$3/MWh on DA A/S Impact Test Threshold
 - DA NCPC credit calculation for Imports (clean-up, not related to IMM recommendations)
- Today, we'll walk through:
 - ISO's estimates of historical cost impacts associated with proposed changes
 - ISO's proposed tariff language changes

APRIL MC FOLLOW-UP



FER Demand Quantity Rationale for Change

- The current implementation of the Forecast Energy Requirement constraint in the DAM can have the effect of inefficiently over-committing or over-clearing the system relative to the reliability need
- This is because it tends not to account for FtM W/S output to the same extent as the ISO's reliability evaluation, the Reserve Adequacy Analysis (RAA)
 - RAA generally counts on FtM W/S at forecast
 - FER generally counts on FtM W/S below forecast
- ISO proposal aligns the FER's treatment of FtM W/S output with the RAA's treatment, addressing the potential to over-commit or over-clear the system
- ISO proposal also aligns FER's treatment of FtM W/S with longstanding treatment of behind-the-meter W/S in RAA
 - Expected output of all wind and solar resources will be fully reflected in the FER, regardless of the location of the meter



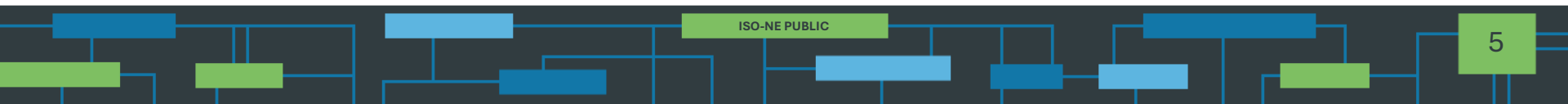
FER Demand Quantity Adjustment Proposal

- ISO proposes to adjust the FER Demand Quantity (currently set equal to the ISO's load forecast) down by the expected amount of forecasted but uncleared real-time FtM W/S generation

Proposed FER DQ = Load Forecast –

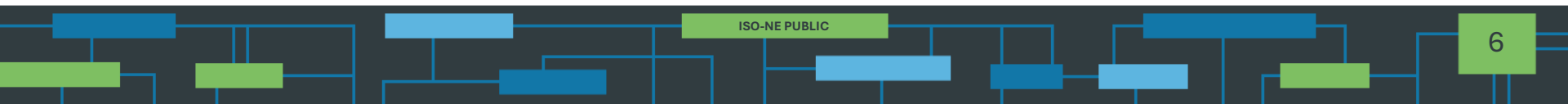
$\max(\text{FtM W/S Forecast} - \text{Expected FtM W/S Cleared Energy and EIR}, 0)$

- “FtM W/S Forecast” reflects the medium-term 50/50 forecast of FtM wind and solar production
 - This value may be adjusted downward based upon anticipated transmission constraints or the forecasted output of non-commercial resources
- “Expected FtM W/S Cleared Energy and EIR” reflects the quantities produced by the “initial” case of the DAM clearing process
 - These values align closely with the “final” values produced by the DAM's security constrained economic dispatch process for FtM W/S resources

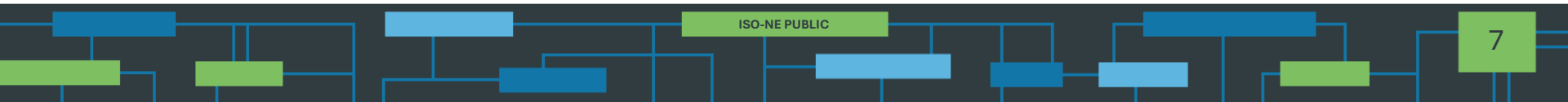


Reliability Considerations

- The adjustment to the FER DQ is intended to align the application of the FER constraint in the DAM with existing reliability processes and address the potential for over-clearing the system
- The NPF adjustment reflects the reliability needs of system operations, given the market and operational improvements
 - See [April 2026 RC presentation](#)
- Strike price floor proposal will reduce incentives for certain resources in certain hours but maintain strong incentives for DA A/S sellers in high-load and high-gas priced hours when reliability is most at risk
 - See [April 2026 MC presentation](#)



ESTIMATES OF THE EFFECT OF PROPOSED CHANGES ON MARKET OUTCOMES



Analysis Approach

- ISO used an in-house DAM simulation tool to perform estimates of what market outcomes would have been if proposed changes had been in effect for the first year of the DA A/S market's operation
 - March 2025 – February 2026
- Estimates produced by this tool reflect a back-cast of first-year results under certain assumptions **and are not a forecast of expected future results**
- **Future years' outcomes may differ** for many possible reasons:
 - Higher or lower fuel costs, milder or more severe future summer or winter weather, more or less DA energy demand, different A/S offers or market participation, etc.

Analysis Approach (*cont'd*)

- Simulations use actual historical inputs where applicable, including DA energy supply offers, DA energy demand bids, and DA A/S offers
- Real-time LMP is assumed to be unchanged from history for purposes of cost estimates
 - RT LMP affects DA A/S closeout charges, as well as the cost of incremental RT energy
- In order to get a meaningful estimate of the effects on market outcomes, proposed changes must be modeled simultaneously
 - Due to co-optimization, the combined effect of all three changes together would not equal the sum of the effects of each individual change

Scenarios

- We modeled two scenarios because of certain assumptions required regarding changes to DAM inputs
- Scenario 1: FER DQ adjustment and NPF = 115% (no strike price floor)
 - No significant assumptions are required
 - ISO can directly calculate updated DAM inputs (new FER DQ, new FRS DQs) using historical data
- Scenario 2: FER DQ adjustment, NPF = 115%, strike price floor
 - An assumption is required regarding how DA A/S offer prices would change with a new value for the strike price
 - We scaled historically observed DA A/S offer prices by a ratio that reflects the change in expected closeout and risk from a different (higher) K:
$$\frac{\{(E[\text{Closeout}] + \text{Risk Premium})_{\text{Proposed } K} + \text{AIC}\}}{\{(E[\text{Closeout}] + \text{Risk Premium})_{\text{Current } K} + \text{AIC}\}}$$
 - We assume no changes to participation in the DA A/S market in this scenario
- The ISO cannot accurately predict how DA A/S offer prices or participation levels may change as a result of the proposed floor for the strike price

Scenarios (*cont'd*)

- The results of Scenarios 1 and 2 are considered in the context of two additional scenarios, each produced using the DAM simulation tool
- **Current Market Rules** – this scenario reflects outcomes of the DAM with the existing DA A/S rules in place
 - Using the simulation tool here allows for an apples-to-apples comparison across all scenarios
 - The DAM simulation tool aligns very well with ISO's production DAM processes
- **No DA A/S** – this scenario reflects estimated market outcomes if DA A/S rules had not been in place
- The estimated incremental cost of a scenario is the difference between that scenario's cost and the cost of the No DA A/S scenario

Scenario 1: Estimated Cost Impacts

- Collectively, the proposed adjustment to the FER DQ and NPF would have reduced the first-year incremental costs of the DA A/S design by an estimated ~\$269M (28%)
 - The FER DQ adjustment plays the larger role in cost reduction here, as this demand quantity can be reduced by larger amounts than the FRS demand quantities

Id	Category	No DA A/S	Incremental DA A/S Costs (Current Rules - No DA A/S) (\$M)	Incremental DA A/S Costs under Partial Proposal (Scenario 1 - No DA A/S) (\$M)	Percent Change in Incremental DA A/S Costs from Partial Proposal
<i>DA Energy</i>					
[1]	DA LMP	\$10,437	(\$309)	(\$2)	99%
[2]	FER	\$0	\$1,026	\$488	-52%
[3]	Cost of Incremental RT Energy	\$140	(\$4)	\$10	340%
[4]	<i>Energy-Specific Costs/Revenues</i>	<i>\$10,577</i>	<i>\$712</i>	<i>\$496</i>	<i>-30%</i>
<i>DA Ancillary Services</i>					
[5]	FRS Credits	\$0	\$428	\$381	-11%
[6]	EIR Credits	\$0	\$25	\$10	-59%
[7]	DA A/S Closeout Charges	\$0	(\$192)	(\$183)	5%
[8]	<i>DA A/S-Specific Costs/Revenues</i>	<i>\$0</i>	<i>\$261</i>	<i>\$208</i>	<i>-20%</i>
<i>Total</i>					
[9]	Total Costs/Revenues	\$10,577	\$974	\$705	-28%

Scenario 1: Estimated Clearing Price Impacts

- FER Price shows an estimated average decrease of 53%, reflecting reductions in the FER demand quantity
 - There is a partially offsetting increase in DA LMP
- Estimated FRS clearing prices decrease more moderately, in line with moderate decreases in FRS demand quantities stemming from the 115% NPF

Category	Current DA A/S Rules (\$/MWh)	Scenario 1: FER DQ and NPF Adjustments (\$/MWh)	Delta (\$/MWh)	Percent Delta (%)
DA Hub LMP	\$71.03	\$73.29	\$2.26	3%
FER Price	\$7.27	\$3.42	-\$3.85	-53%
TMSR Price	\$22.60	\$20.76	-\$1.84	-8%
TMNSR Price	\$21.42	\$19.51	-\$1.91	-9%
TMOR Price	\$19.30	\$17.64	-\$1.66	-9%

Table shows average estimated clearing prices from Mar 2025 to Feb 2026

Scenario 2: Estimated Cost Impacts

- Collectively, the ISO's proposed adjustments (FER DQ, NPF, and strike price floor) serve to reduce the estimated first-year incremental costs of the DA A/S design by ~\$292M (30%)
 - This estimate reflects all the caveats associated with Scenario 2 noted on slide 10

Id	Category	NO DA A/S	Incremental DA A/S Costs (Current Rules - No DA A/S) (\$M)	Incremental DA A/S Costs under Full Proposal (Scenario 2 - No DA A/S) (\$M)	Percent Change in Incremental DA A/S Costs from Full Proposal
<i>DA Energy</i>					
[1]	DA LMP	\$10,437	(\$309)	\$79	125%
[2]	FER	\$0	\$1,026	\$390	-62%
[3]	Cost of Incremental RT Energy	\$140	(\$4)	\$14	429%
[4]	<i>Energy-Specific Costs/Revenues</i>	\$10,577	\$712	\$482	-32%
<i>DA Ancillary Services</i>					
[5]	FRS Credits	\$0	\$428	\$287	-33%
[6]	EIR Credits	\$0	\$25	\$9	-63%
[7]	DA A/S Closeout Charges	\$0	(\$192)	(\$96)	50%
[8]	<i>DA A/S-Specific Costs/Revenues</i>	\$0	\$261	\$200	-23%
<i>Total</i>					
[9]	Total Costs/Revenues	\$10,577	\$974	\$682	-30%

Scenario 2: Estimated Clearing Price Impacts

- FRS clearing prices are estimated to decrease by ~30%
 - This is driven by reductions in FRS offer prices, which in turn are driven by lower expected closeout and risk components
- FER Price is further reduced, relative to Scenario 1
 - This is driven in part by reductions in EIR offer prices
 - DA LMP sees a partially offsetting increase
- Caveat: These results are reflective of ISO's methodology for adjusting DA A/S offer prices and assumptions around participation, which may differ from participants' actual offer behavior in the future

Category	Current DA A/S Rules (\$/MWh)	Scenario 2: FER DQ, NPF, and Strike Price Floor Adjustments (\$/MWh)	Delta (\$/MWh)	Percent Delta (%)
DA Hub LMP	\$71.03	\$73.93	\$2.90	4%
FER Price	\$7.27	\$2.62	-\$4.65	-64%
TMSR Price	\$22.60	\$16.07	-\$6.53	-29%
TMNSR Price	\$21.42	\$14.73	-\$6.70	-31%
TMOR Price	\$19.30	\$12.98	-\$6.32	-33%

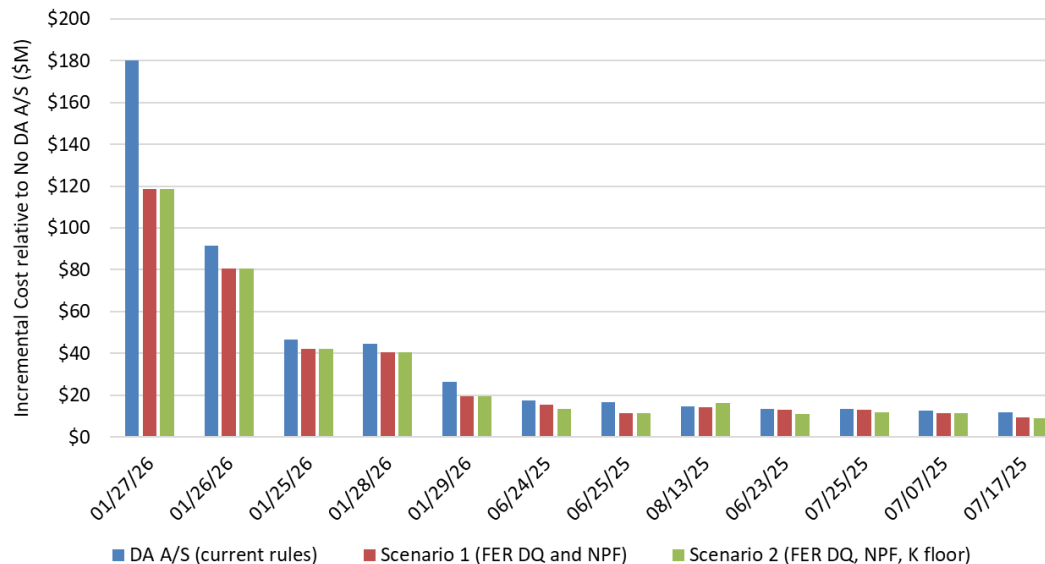
Table shows average estimated clearing prices from Mar 2025 – Feb 2026

Scenario 1 vs. Scenario 2

- One notable result is that the historical incremental costs of the DA A/S design are only moderately reduced by application of the strike price floor
 - Incremental cost reduction from Scenario 1 (no strike floor): 28%
 - Incremental cost reduction from Scenario 2 (with strike floor): 30%
- This result is driven by the offsetting effects of the strike price floor on DA A/S clearing prices and realized closeout charges
 - A higher strike price reduces DA A/S offer prices, driving down DA A/S clearing prices (reducing credits to supply and costs to load)
 - A higher strike price reduces the frequency and magnitude of non-zero closeout charges (reducing costs to supply and credits to load)
- Cross-product opportunity costs play a role in DA A/S clearing price determination
 - DA A/S clearing prices in Scenario 2 do not decrease to the level some might expect, given increase in K (see Appendix 2 for a conceptual example)
 - The effect of opportunity costs on clearing prices is sensitive to assumptions around DA A/S participation levels

Effect of Proposal on High-Cost Days

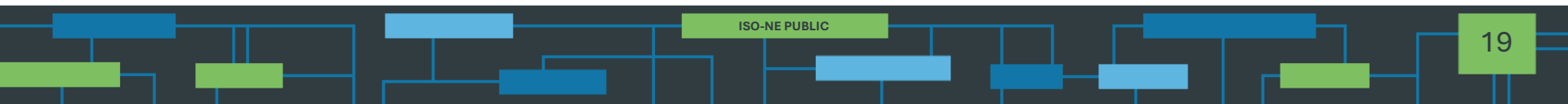
- During the first year with DA A/S, twelve days accounted for ~50% of the incremental cost of the DA A/S market design (i.e., comparing Current Rules scenario to No DA A/S scenario)
- Proposal is estimated to reduce incremental costs on those historical dates by ~\$103M (35%)
 - Significant impact on 1/27, driven primarily by reductions in FER costs
 - FER DQ reduced by ~300 MW on average on this day (min = 116 MW, max = 570 MW)
 - Moderate reductions in DQ can be impactful when system is stressed and operating on the steepest portion of the supply curve



Key Takeaways

- ISO estimates that the proposed changes would have reduced the first-year (Mar 2025 – Feb 2026) incremental costs of the DA A/S market by an estimated \$292M (30%)
 - These estimates are not predictions of future results and are dependent on assumptions around DA A/S offer behavior and participation

PROPOSED TARIFF LANGUAGE



Summary of Proposed Tariff Changes

- Section III.1.8.2 Day-Ahead Ancillary Services Strike Price
 - Define and add a floor value for the Day-Ahead Ancillary Services Strike Price
- Section III.A.8.1.2 Impact Test
 - Add a floor to the Impact Test Threshold of \$3/MWh
- Section III.1.8.4 Forecast Energy Requirement Demand Quantity
 - Modify the hourly Forecast Energy Requirement Demand Quantity to reflect expected reliability contribution of front-of-the-meter dispatchable wind and solar resources
- Section III.F.2.3.1 DA External Transaction Import NCPC Credits
 - Update the application of Forecast Energy Requirement price when calculating Hourly Revenue for DA NCPC credits for External Transactions
 - Prevents FER Price (FERP)-ineligible imports from receiving the FERP through DA NCPC credits

Summary of Proposed Tariff Changes

Section III.1.8.2 Day-Ahead Ancillary Services Strike Price

Tariff Section	Tariff Change	Reason for Change
III.1.8.2 (a)	Insert “ <u>the values calculated in accordance with subsections (1) and (2) below:</u> <u>(1) the greater of ” and “and (2) a floor value derived in accordance with subsection (c) below.”</u> ”	Add a floor value for the DA A/S Strike Price
III.1.8.2 (b)	Strike “forecast used to determine the Day Ahead Ancillary Services Strike Price” and insert “ <u>value calculated in subsection (a)(1) above</u> ”	Clarity
III.1.8.2(c)	Strike “(c) In the event that the ISO is not able to utilize the ISO-developed forecasting algorithm described in subsection (b) above due to hardware, software, or telecommunications problems, human error, or exigent circumstances not contemplated by this market rule, the ISO shall determine the Day-Ahead Ancillary Services Strike Price using the best forecast available and shall disclose the use of such substitute forecast to Market Participants as soon as practicable.”	Re-locating language to new subsection (d)

Summary of Proposed Tariff Changes

Section III.1.8.2 Day-Ahead Ancillary Services Strike Price

Tariff Section	Tariff Change	Reason for Change
III.1.8.2(c)	Insert “(c) The floor value in subsection (a)(2) above shall be determined daily based on the marginal cost of supplying energy by an efficient, distillate-fired combustion turbine generator, reflecting both emissions costs and the lowest-priced distillate fuel available. The ISO shall describe to Market Participants the heat rate, emissions cost, and fuel prices that it uses to determine the value in subsection (a)(2).”	Define a floor value for the DA A/S Strike Price
III.1.8.2(d)	Re-locate and revise prior subsection (c): “(d) In the event that the ISO is not able to utilize the methods in subsections (a) through (c) above due to hardware, software, or telecommunications problems, human error, or exigent circumstances not contemplated by this market rule, the ISO shall determine the Day-Ahead Ancillary Services Strike Price using the best forecast and floor value available and shall disclose the use of such substitute method to Market Participants as soon as practicable.”	Revised to reflect the floor component of the strike price calculation

- Heat rate and fuels noted in III.1.8.2(c) will be specified in the [DA A/S Monthly RT LMP Modeling Memo](#)

Summary of Proposed Tariff Changes

Section III.A.8.1.2 Impact Test

Tariff Section	Tariff Change	Reason for Change
III.A.8.1.2	Replace “greater” with “ <u>higher</u> ”	Preventing word repetition
III.A.8.1.2	Insert “ <u>the greater of (a) \$3/MWh and (b)</u> ”	Add a floor of \$3/MWh to Impact Test Threshold

Summary of Proposed Tariff Changes

Section III.1.8.4 Forecast Energy Requirement Demand Quantity

Tariff Section	Tariff Change	Reason for Change
III.1.8.4	Revised section: “For each hour of the Operating Day, the Forecast Energy Requirement Demand Quantity shall be: <u>equal to</u> <u>(1) the ISO forecast for the total load in the New England Control Area produced pursuant to Section III.1.10.1A(h) of this Market Rule 1, less</u> <u>(2) the greater of (i) the forecast of front-of-the-meter dispatchable wind and solar resources’ total real-time energy supply, as adjusted for any expected operating conditions, less the total energy supply and ancillary services from such resources forecast to clear in the Day-Ahead Market and (ii) zero.”</u>	Modify the hourly FER DQ to reflect expected reliability contribution of FTM dispatchable wind and solar resources

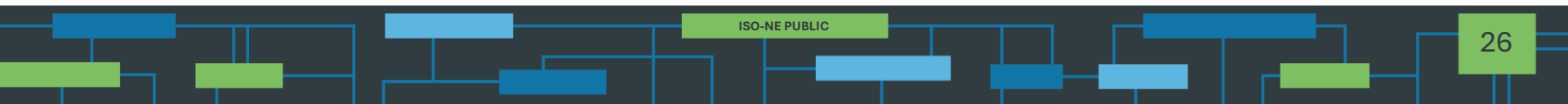
Summary of Proposed Tariff Changes

Section III.F.2.3.1.3 Hourly Revenue (subsection of III.F.2.3.1 DA External Transaction Import NCPC Credits)

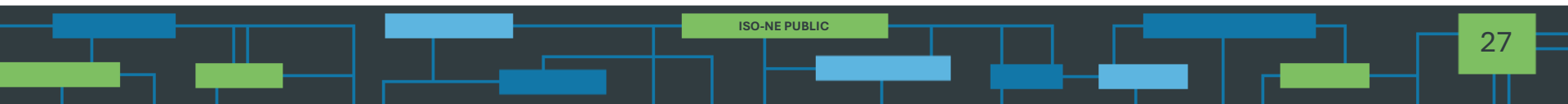
Tariff Section	Tariff Change	Reason for Change
III.F.2.3.1.3	Insert “not” and “credit.” Revised sentence: “The Day-Ahead revenue for a pool-scheduled External Transaction import at an External Node for an hour is equal to the cleared Day-Ahead transaction amount (MW) for the hour multiplied by the Day-Ahead Price, where the Day-Ahead Price is equal to the Day-Ahead Locational Marginal Price plus the Forecast Energy Requirement Price, <u>not</u> subject to the <u>credit</u> conditions specified in Section III.3.2.1(q)(4)(ii).”	Prevent FERP-ineligible imports from receiving FERP via DA NCPC

No Tariff Changes Are Proposed for the NPF

- ISO operators may require the flexibility to adjust the NPF in real time, to respond to rapidly changing system conditions
 - Codifying the NPF in the Tariff would limit this flexibility and potentially be detrimental to reliable system operations
- Currently, the Tariff does not specify how real-time operating reserve requirements are determined
 - The NPF is but one component of these calculations
- Instead, real-time operating reserve requirement calculations are described in [OP-8](#)



NEXT STEPS AND STAKEHOLDER SCHEDULE



Stakeholder Schedule

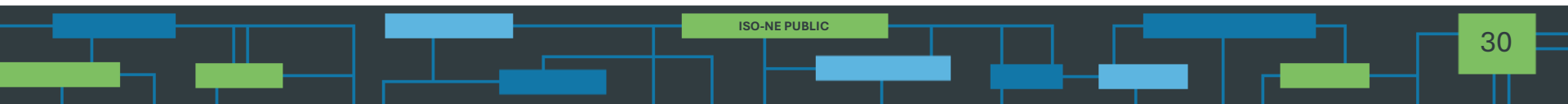
Stakeholder Committee and Date	Scheduled Project Milestone
Markets Committee April 14-16, 2026	Overview of ISO proposal
Reliability Committee April 22, 2026	Review change to the Non-Performance Factor
Markets Committee May 12-13, 2026	Estimate of market impacts and initial review of proposed Tariff language
Markets Committee June 9-10, 2026	Additional review of proposed Tariff language, and vote
Participants Committee June 16-18, 2026	Vote

Questions



APPENDIX 1

Detailed results of estimates of the proposal's impacts on costs



Scenario 1: Estimated Cost Impact Details

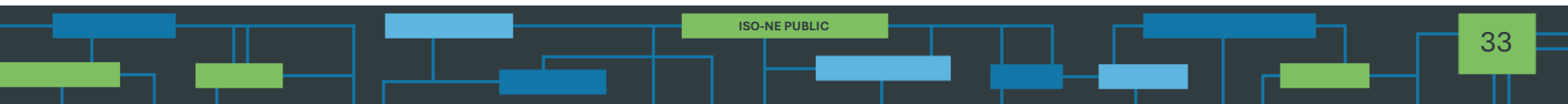
Id	Category	No DA A/S	Current DA A/S Rules (\$M)	Scenario 1: FER DQ and NPF Adjustments (\$M)	Delta (Current Rules - Scenario 1) (\$M)	Percent Delta (Current Rules vs Scenario 1) (%)	Incremental DA A/S Costs (Current Rules - No DA A/S) (\$M)	Incremental DA A/S Costs under Partial Proposal (Scenario 1 - No DA A/S) (\$M)	Percent Change in Incremental DA A/S Costs from Partial Proposal
<i>DA Energy</i>									
[1]	DA LMP	\$10,437	\$10,127	\$10,435	\$308	3%	(\$309)	(\$2)	99%
[2]	FER	\$0	\$1,026	\$488	(\$538)	-52%	\$1,026	\$488	-52%
[3]	Cost of Incremental RT Energy	\$140	\$136	\$150	\$14	10%	(\$4)	\$10	340%
[4]	<i>Energy-Specific Costs/Revenues</i>	\$10,577	\$11,290	\$11,073	(\$216)	-2%	\$712	\$496	-30%
<i>DA Ancillary Services</i>									
[5]	FRS Credits	\$0	\$428	\$381	(\$48)	-11%	\$428	\$381	-11%
[6]	EIR Credits	\$0	\$25	\$10	(\$15)	-59%	\$25	\$10	-59%
[7]	DA A/S Closeout Charges	\$0	(\$192)	(\$183)	\$9	-5%	(\$192)	(\$183)	5%
[8]	<i>DA A/S-Specific Costs/Revenues</i>	\$0	\$261	\$208	(\$53)	-20%	\$261	\$208	-20%
<i>Total</i>									
[9]	Total Costs/Revenues	\$10,577	\$11,551	\$11,282	(\$269)	-2%	\$974	\$705	-28%

Scenario 2: Estimated Cost Impact Details

Id	Category	No DA A/S	Current DA A/S Rules (\$M)	Scenario 2: FER DQ, NPF, and Strike Price Floor Adjustments (\$M)	Delta (Current Rules - Scenario 2) (\$M)	Percent Delta (Current Rules vs Scenario 2) (%)	Incremental DA A/S Costs (Current Rules - No DA A/S) (\$M)	Incremental DA A/S Costs under Full Proposal (Scenario 2 - No DA A/S) (\$M)	Percent Change in Incremental DA A/S Costs from Full Proposal
<i>DA Energy</i>									
[1]	DA LMP	\$10,437	\$10,127	\$10,515	\$388	4%	(\$309)	\$79	125%
[2]	FER	\$0	\$1,026	\$390	(\$636)	-62%	\$1,026	\$390	-62%
[3]	Cost of Incremental RT Energy	\$140	\$136	\$154	\$18	13%	(\$4)	\$14	429%
[4]	<i>Energy-Specific Costs/Revenues</i>	\$10,577	\$11,290	\$11,059	(\$230)	-2%	\$712	\$482	-32%
<i>DA Ancillary Services</i>									
[5]	FRS Credits	\$0	\$428	\$287	(\$141)	-33%	\$428	\$287	-33%
[6]	EIR Credits	\$0	\$25	\$9	(\$16)	-63%	\$25	\$9	-63%
[7]	DA A/S Closeout Charges	\$0	(\$192)	(\$96)	\$96	-50%	(\$192)	(\$96)	50%
[8]	<i>DA A/S-Specific Costs/Revenues</i>	\$0	\$261	\$200	(\$61)	-23%	\$261	\$200	-23%
<i>Total</i>									
[9]	Total Costs/Revenues	\$10,577	\$11,551	\$11,259	(\$292)	-3%	\$974	\$682	-30%

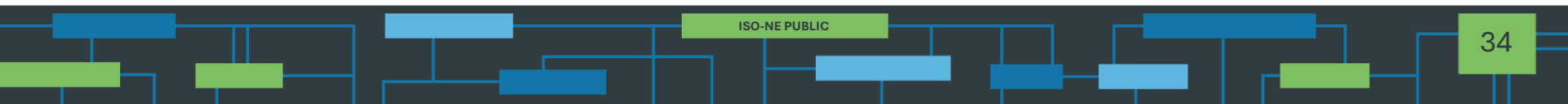
APPENDIX 2

Conceptual example illustrating how cross-product opportunity costs affect DA A/S clearing prices in the context of the ISO's proposed strike price floor



Example Setup

- We'll consider a hypothetical four-resource system with fixed energy demand (850 MW) as well as FRS demand (90 MW)
 - For simplicity, we'll set aside the FER constraint, though similar pricing principles to those demonstrated in this example apply
- We'll illustrate how a DA A/S clearing price is affected by cross-product opportunity costs and can remain “high” even when DA A/S offer prices are significantly reduced (as would be anticipated with the ISO's proposed floor for the strike price)
 - We'll refer to “cross-product opportunity costs” simply as OCs throughout this example



Results Under Current Rules (No K Floor)

- Assume that under the current K, $E[\text{Closeout}] = \$2.80/\text{MWh}$
 - Two units choose to offer DA A/S and have offer prices around $E[\text{Closeout}]$
- Resource D is on the margin for energy and sets DA LMP = $\$70/\text{MWh}$
- Resource C is on the margin for FRS
 - FRS clearing price ($\$23/\text{MWh}$) is composed of this resource's FRS offer price ($\$3/\text{MWh}$) and its OC of providing FRS instead of energy ($\$20/\text{MWh}$)

DAM Inputs				DAM Outputs	
Resource	Ecomax (MW)	Energy Offer (\$/MWh)	FRS Offer Price (\$/MWh)	Cleared DA Energy (MW)	Cleared FRS (MW)
A	700	\$36		700	
B	100	\$39	\$2.60	100	0
C	100	\$50	\$3.00	10	90
D	50	\$70		40	
Total:				850	90

DA LMP (\$/MWh)	FRS CP (\$/MWh)
\$70.00	\$23.00

- OC = DA LMP – Energy Offer
 - DA LMP = $\$70/\text{MWh}$
 - Resource C's energy offer = $\$50/\text{MWh}$
 - OC = $\$20/\text{MWh}$
- Note:** OC has a bigger effect on FRS clearing price than the FRS offer price in this example

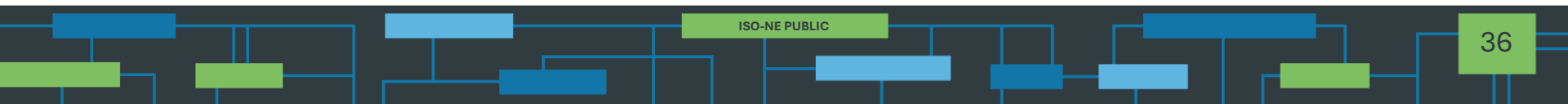
Results with Strike Price Floor

- With the strike price floor applied, assume $E[\text{Closeout}] = \$0.28/\text{MWh}$
 - $E[\text{Closeout}]$ is reduced by a factor of 10 as a result of the floor
 - FRS offer prices are similarly scaled down by a factor of 10 as a result
- Resource C is still on the margin for FRS
 - FRS clearing price is $\$20.30/\text{MWh}$ and is composed of this resource's A/S offer price ($\$0.30/\text{MWh}$) and its OC of providing FRS instead of energy (still $\$20/\text{MWh}$)

DAM Inputs				DAM Outputs	
Resource	Ecomax (MW)	Energy Offer (\$/MWh)	FRS Offer Price (\$/MWh)	Cleared DA Energy (MW)	Cleared FRS (MW)
A	700	\$36		700	
B	100	\$39	\$0.26	100	0
C	100	\$50	\$0.30	10	90
D	50	\$70		40	
Total:				850	90

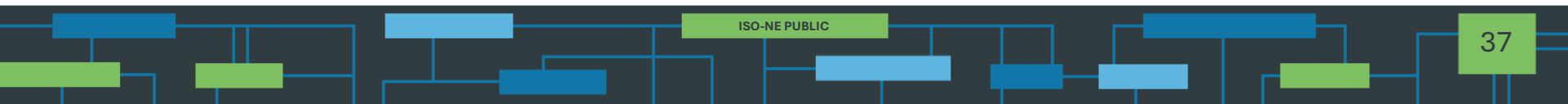
DA LMP (\$/MWh)	FRS CP (\$/MWh)
\$70.00	\$20.30

- Key Takeaway:** Even with a tenfold decrease in FRS offer prices, FRS clearing price remains in the $\sim\$20$ range as a result of cross-product opportunity costs



APPENDIX 3

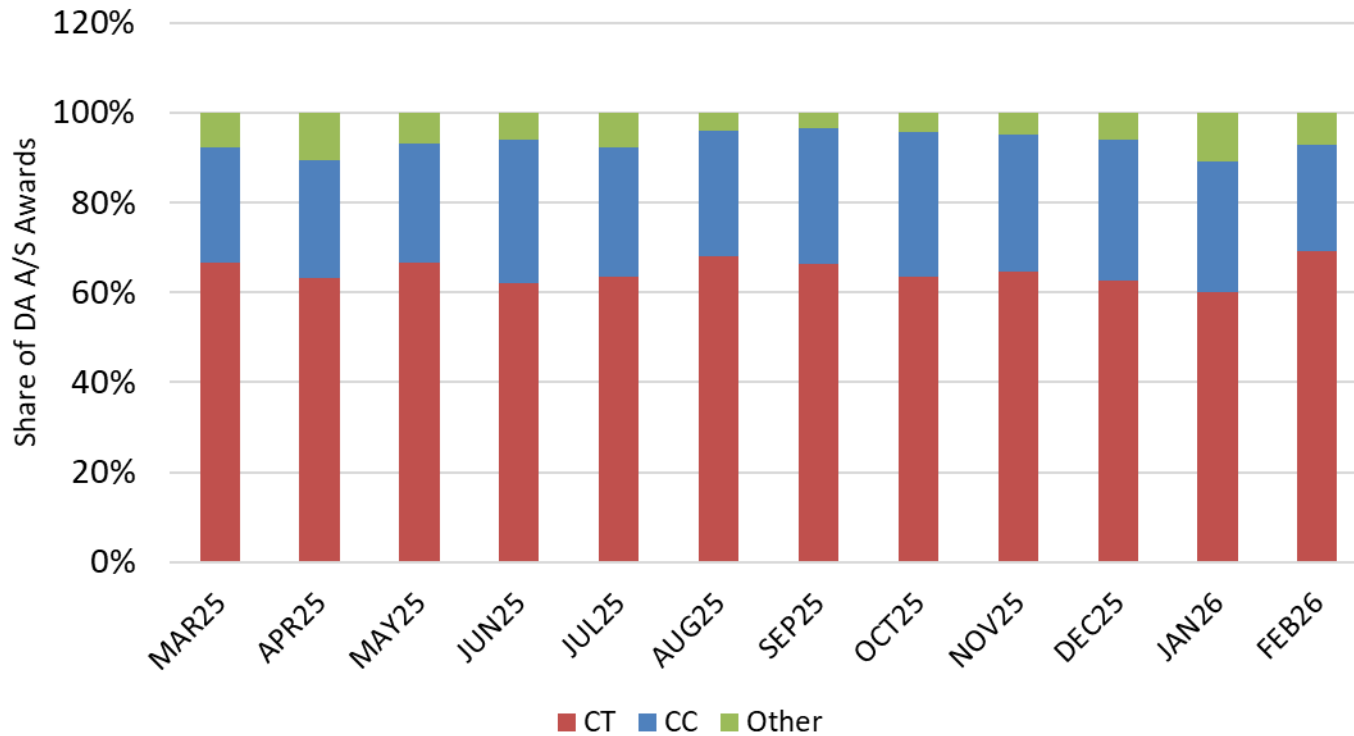
*Information requested at the April 2026 Markets
Committee Meeting*



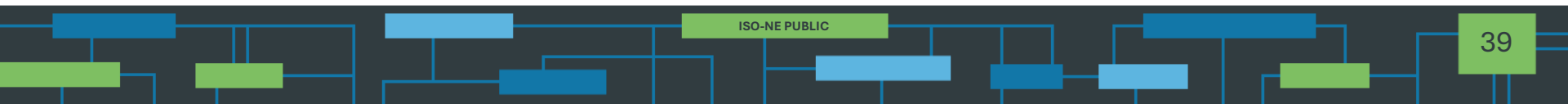
Wind and Solar Forecast Accuracy

- At the April 2026 MC, participants expressed interest in better understanding the accuracy of the ISO's wind and solar forecasts
- The ISO provides a [detailed analysis of this forecast accuracy](#) to the Emerging Technologies Working Group (ETWG) on an annual basis
- In addition, the ISO publicly publishes related data, at an hourly granularity, that may be of interest to participants
 - FtM Wind and Solar Forecast data is posted [here](#)
 - FtM Real-time Wind and Solar output is available via [ISO Express](#)
- The accuracy of the wind and solar forecasts is not directly relevant to the ISO's proposal to adjust the FER Demand Quantity
 - The Reserve Adequacy Analysis (RAA) process currently uses the discrete medium-term 50/50 forecast of wind and solar output when evaluating reliability
 - The ISO's proposal aligns the DAM's treatment of the reliability contribution of these resources with this existing and long-standing reliability analysis

Monthly DA A/S Supply Mix

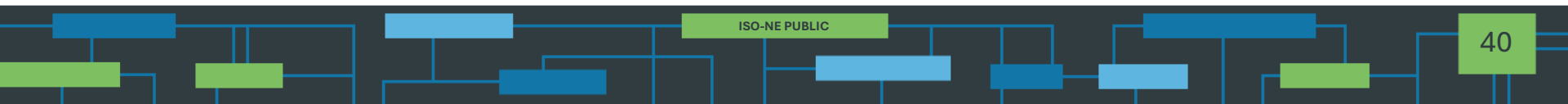


- DA A/S supply mix is consistent over time

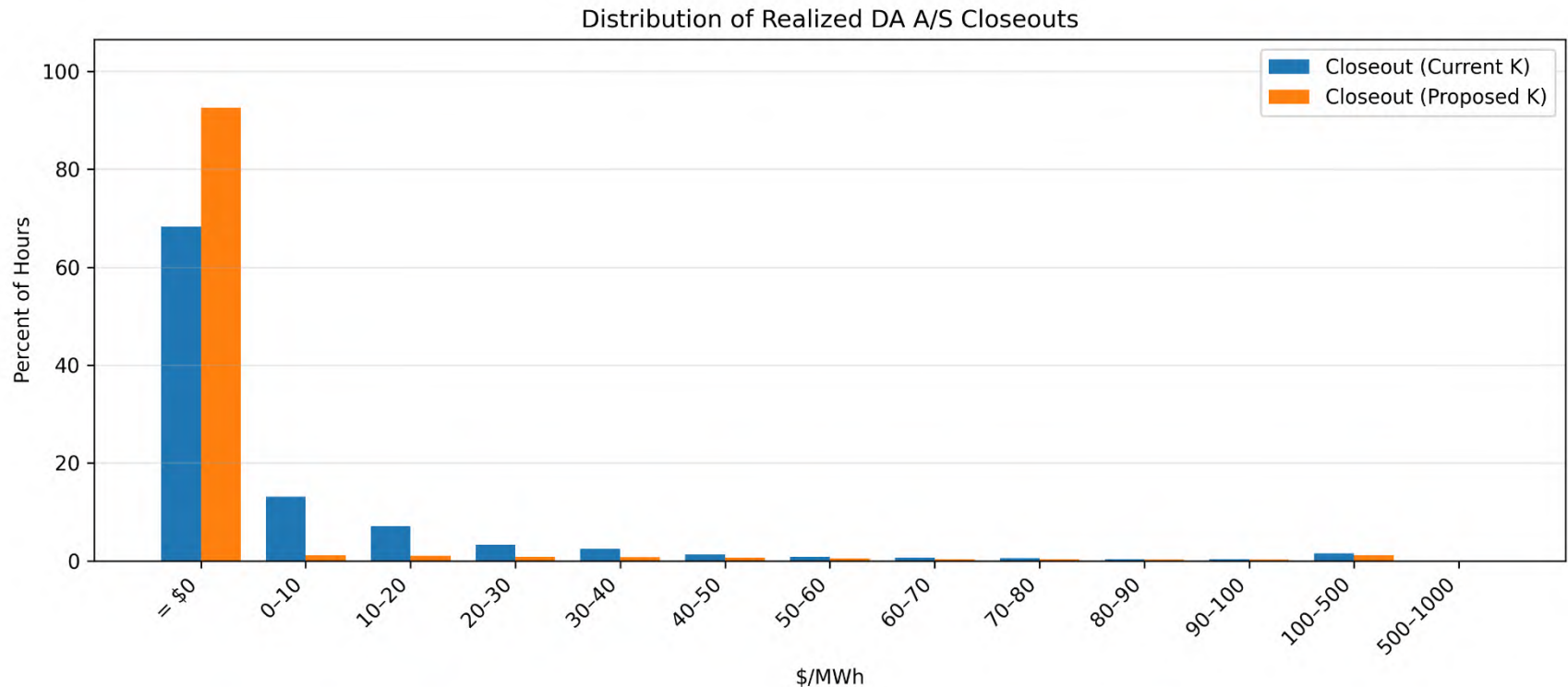


Fuel Index Specifications

- ISO proposes to use the lowest cost of four distillate fuels in determining the floor for the strike price
 - These fuels are ULS Kerosene, ULS Diesel, LS Jet Kerosene, and No2 Oil
 - Cost considers both the price of fuel, as well as relevant emissions costs
- The fuel indices the ISO will use for determining the strike price are provided by Argus and are updated on a daily basis, excluding non-trading periods (i.e., holidays and weekends)
 - These fuel indices are the same as those that are used by the IMM in determining energy market reference levels
 - See Appendix A of the [eMarket User Guide](#)
- Emissions costs (CO₂, SO_x, NO_x) are provided by Evolution Markets

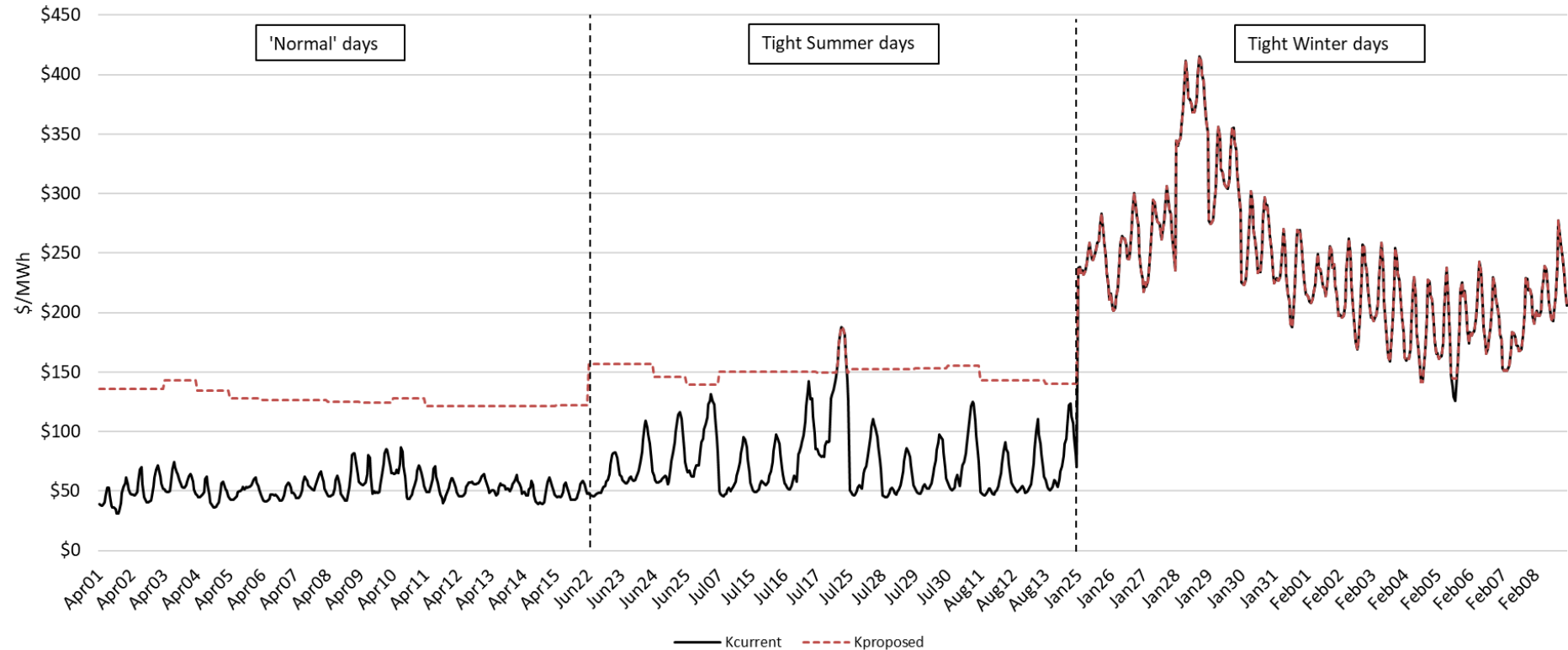


Realized Closeout Costs

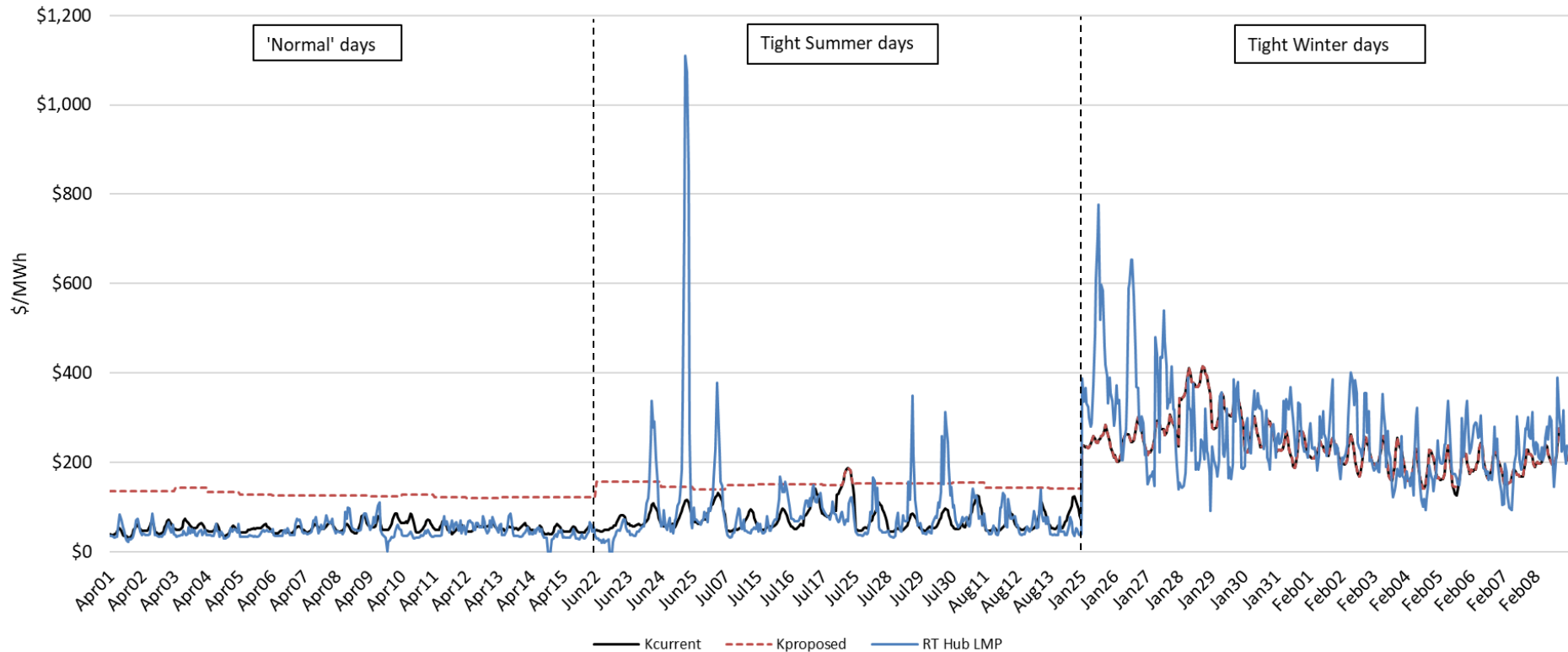


	Actual K	Proposed K
Hours with Non-Zero Closeouts (% of hours)	32%	7%
Average Closeout (\$/MWh)	9	5
95 th Percentile Closeout (\$/MWh)	45	21
99 th Percentile Closeout (\$/MWh)	126	107

Strike Price Proposal on Representative Days



Strike Price Proposal on Representative Days (cont'd)



To: Participants Committee

From: Jasleen Singh, Secretary, Markets Committee

Date: June 9, 2026

Subject: Actions of the Markets Committee from the June 2026 Meeting

This memo is to notify the Participants Committee (“PC”) of the following actions taken by the Markets Committee (MC) at the June 2026 MC meeting. A quorum was established.

(Agenda Item 1.A) Meeting Minutes

ACTION: APPROVED

The following motion was moved and seconded by the Markets Committee:

Resolved, that the Markets Committee approves the minutes for the May 12-14, 2026 Markets Committee meeting, May 12-14, 2026 Joint meeting of the Markets and Reliability Committees, May 21, 2026 Joint meeting of the Reliability and Markets Committees, and April 21, 2026 Joint meeting of the Transmission, Reliability, and Markets Committees, as circulated for the June 9-11, 2026 NEPOOL Markets Committee meeting, with such further non-substantive changes as the Chair and Vice-Chair may approve.

Based on a voice vote, the motion passed with none opposed and one abstention in the End User Sector.

(Agenda Item No. 2.A) – NEPOOL Generation Information System (GIS) Working Group | Request for referral - Certificate Statistics Public Report

ACTION: REFERRED

The request was referred to the NEPOOL GIS Operating Rules Working Group by the Markets Committee to consider potential changes to the GIS to reflect improvements to the Certificate Statistics Public Report.

(Agenda Item No. 2.B) – NEPOOL GISWG | Request for referral - ME/RI RPS

ACTION: REFERRED

The request was referred to the NEPOOL GIS Operating Rules Working Group by the Markets Committee to consider changes to the GIS Rules to provide that air emission data is not required to be entered in the GIS in order for biomass and landfill gas facilities to be denoted as eligible for the Maine and Rhode Island Renewable Portfolio Standards.

(Agenda Item No. 3.0) – Day-Ahead Ancillary Services Post-Implementation Adjustments

The following main motion was moved and seconded by the Markets Committee:

Resolved, that the Markets Committee recommends the Participants Committee support ISO's proposed adjustments to the Day-Ahead Ancillary Services market and related revisions to: Sections III.3.2.1(q)(4), III.1.8.2, III.1.8.4, III.A.8.1.2, and III.F.2.3.1.3, of the Transmission, Markets, and Services Tariff, as circulated for its June 9-11, 2026 meeting; together with any further changes recommended by this Committee, and such further non-substantive changes as the Chair and Vice-Chair of the Markets Committee may approve.

Before the main motion could be voted, the following motion was moved and seconded by the Markets Committee to amend the main motion as follows:

(Vote 1 – Failed) Agenda Item 3.B – FirstLight Power Amendment – Strike Price Floor Removal

Resolved, that the main motion be amended, as contained in the materials provided by FirstLight Power, to restore the language in Section III.1.8 of the Transmission, Markets, and Services Tariff to its current language, as circulated for its June 9-11, 2026 meeting; together with any further changes recommended by this Committee, and such further non-substantive changes as the Chair and Vice-Chair of the Markets Committee may approve.

The motion to amend was voted, and based on a roll call vote, failed to pass with a vote of 20.83% in favor. The individual Sector votes were Generation (8.33% in favor, 8.33% opposed, 1 abstention), Transmission (0.00% in favor, 16.67% opposed, 0 abstentions), Supplier (12.50% in favor, 4.17% opposed, 8 abstentions), Publicly Owned Entity (0.00% in favor, 16.67% opposed, 0 abstentions), Alternative Resources (0.00% in favor, 16.67% opposed, 3 abstentions), and End User (0.00% in favor, 16.67% opposed, 4 abstentions).

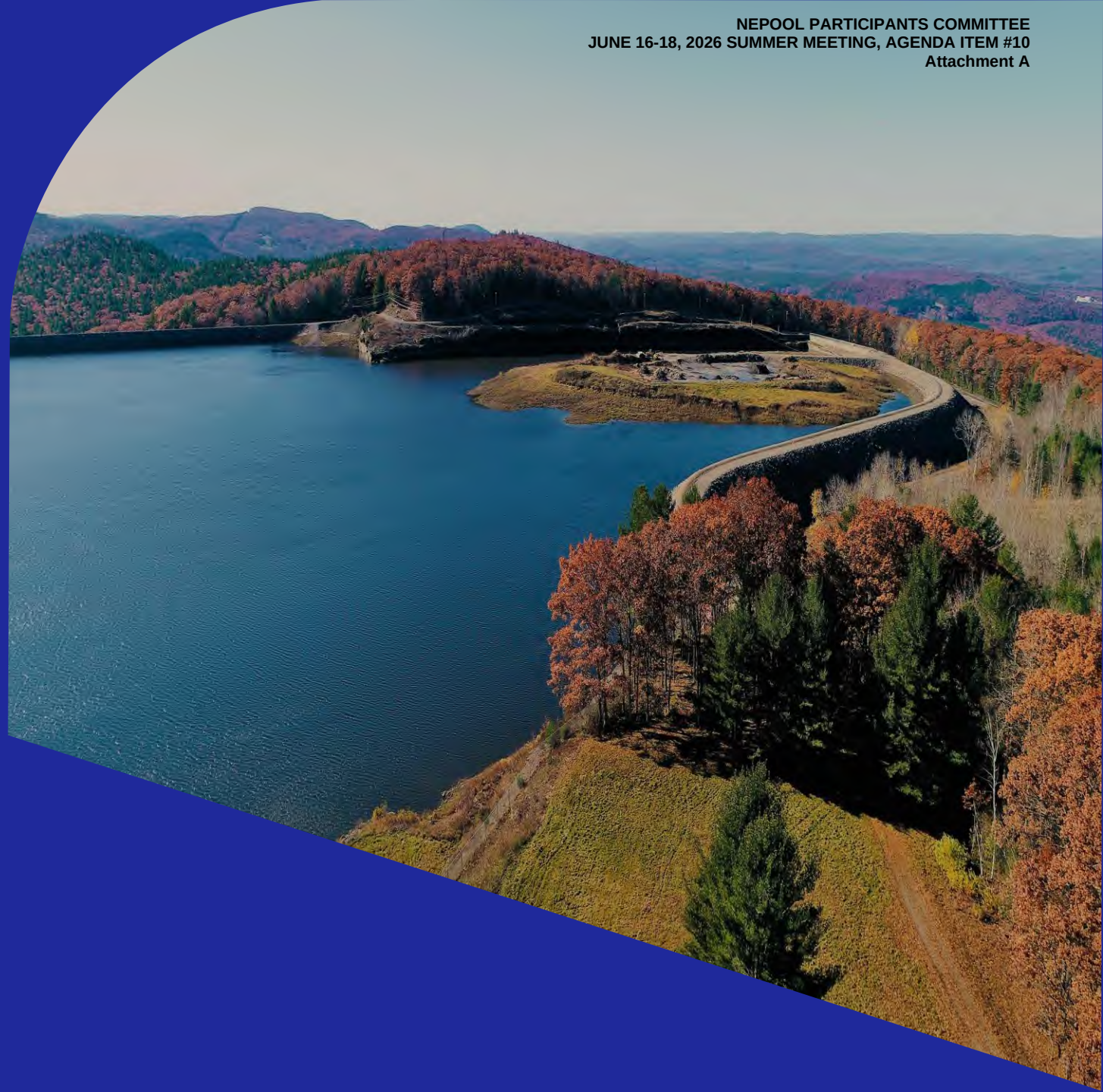
(Vote 2 – Passed) Agenda Item 3.A – ISO-NE's Proposed Day-Ahead Ancillary Services Post-Implementation Adjustments – Unamended Main Motion

ACTION: RECOMMEND SUPPORT

The unamended main motion voted and, based on a roll call vote, passed with a vote of 64.54% in favor. The individual Sector votes were Generation (0.00% in favor, 16.67% opposed, 1 abstention), Transmission (16.67% in favor, 0.00% opposed, 0 abstentions), Supplier (8.33% in favor, 8.33% opposed, 5 abstentions), Publicly Owned Entity (16.67% in favor, 0.00% opposed, 0 abstentions), Alternative Resources (6.20% in favor, 10.46% opposed, 1 abstention), and End User (16.67% in favor, 0.00% opposed, 1 abstention).

DAAS Amendment FirstLight

ISO-NE Markets Committee
June 2026



FirstLight Amendment

Remove the tariff changes implementing the proposed Strike Price Floor from the Post-Implementation DAAS Changes

These changes:

1

- Are too generally defined – lack of clarity creates uncertainty for market participants and leaves too much discretion to ISO-NE on the level of the Strike Price. Any Strike Price floor should be explicitly defined in the tariff.
- Are not justified by the poor tradeoff of 2% consumer cost savings in trade for reducing reserve incentives for over 40% of DAAS resources in 50% of the hours.
- Unfairly require physical resources with energy offers well below the Strike Price Floor (but at or above the expected RTLMP) to provide higher value, uncompensated reserves.

Commit to improving the Gaussian Mixture Model (GMM) derived Strike Price

2

Address known issues like the known price lag at the start and end of major fuel price swings, impact of significant outages, and/or temperature impacts in summer due to training across the full year.



Proposed Tariff Language is Too Vague

ISO-NE proposal to define the Strike Price Floor

Section III.1.8.2

“(c) The floor value in subsection (a)(2) above shall be determined daily based on the marginal cost of supplying energy by an efficient, distillate-fired combustion turbine generator, reflecting both emissions costs and the lowest-priced distillate fuel available. The ISO shall describe to Market Participants the heat rate, emissions cost, and fuel prices that it uses to determine the value in subsection (a)(2).”

This language leaves material elements of the filed rate unspecified

- What heat rate is implied by an efficient, distillate-fired combustion turbine. Is it the 9,000 Btu/kWh example provided by ISO-NE? If not, what is the range of possible Strike Price Floor values? How frequently could it change and with how much notice?
- What emission cost index is used. Is it the RGGI price, opportunity cost of remaining megawatt-hours under license restrictions, etc.?
- What fuel price index will be used (No. 2 oil, ULSD, etc.)? How frequently could it change and with how much notice?

If the tariff does not specify these elements, it could create high uncertainty for market participants considering long-term investments, as key parameters impacting market design could change with unknown frequency and notice periods.



Poor Cost vs. Reliability Tradeoff

- According to ISO-NE analysis, 41-47% of the reserve resources that have cleared in DAAS in 50% of the hours would have reduced financial incentive to perform.
 - While reductions in incentives are largest during lower-load hours, reliability is important during all hours. The November 2025 capacity scarcity event presents a recent reminder that reliability events can occur even when load is not near seasonal peak.
- That significant reduction in reliability incentives would only deliver a 2% reduction in DAAS costs.

Effect on DAAS Incentives by Load Forecast

Percentile of Load Forecast Bin	Stats Across Hours when K changes			Percent Decrease in DA A/S awards fully retaining Incentives
	% Hours K changes	Avg K_{Curr} (\$/MWh)	Avg K_{Prop} (\$/MWh)	
0 - 25th	100%	\$36	\$137	-47%
25 - 50th	100%	\$49	\$141	-41%

From Slide 23 of ISO-NE [presentation](#) at April 2026 MC

Effect on DAAS Costs of Strike Floor Proposal

One notable result is that the historical incremental costs of the DA A/S design are only moderately reduced by application of the strike price floor

- Incremental cost reduction from Scenario 1 (no strike floor): 28%
- Incremental cost reduction from Scenario 2 (with strike floor): 30%

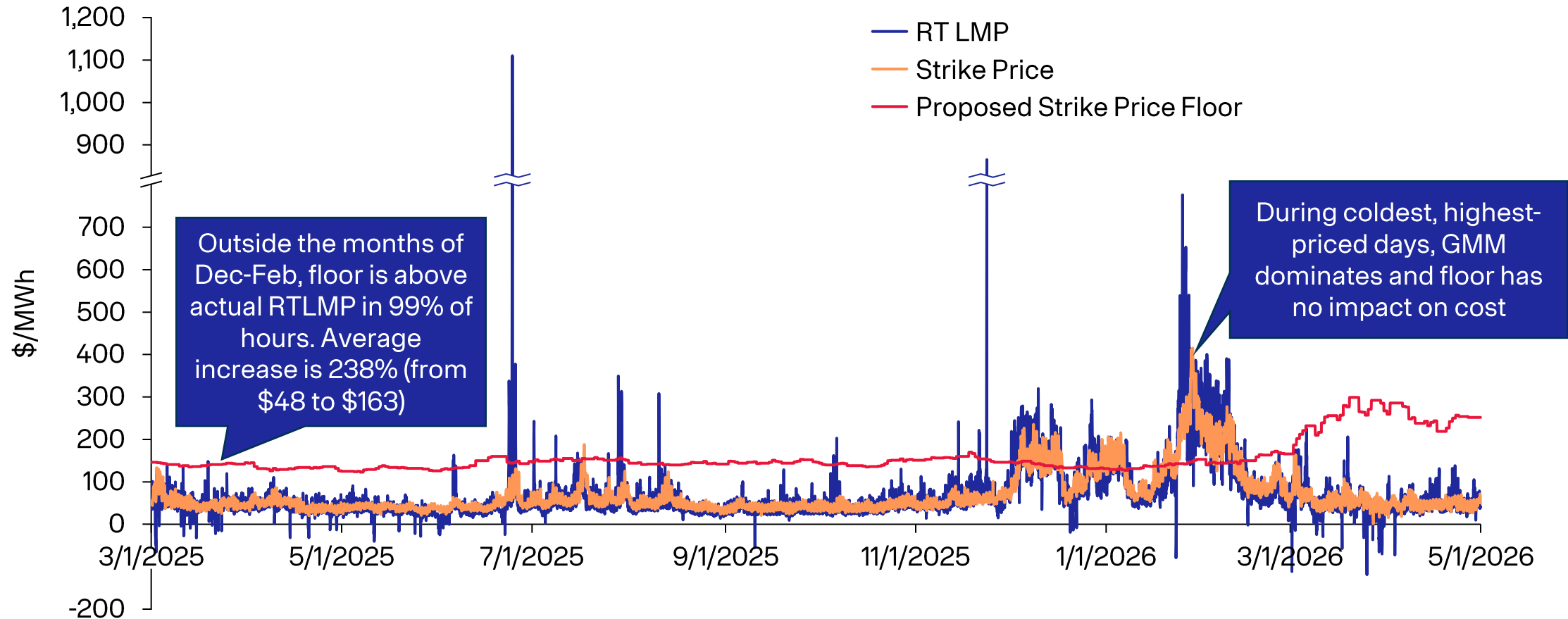
From Slide 16 of ISO-NE [presentation](#) at May 2026 MC



Extent of Reliability Impacts Unsurprising Given Drastic Increase to Strike Price in All But Coldest Period

Proposed Strike Price Floor vs. GMM Strike Price and RT LMP

Strike price floor calculated based on NY Harbor No. 2 Heating Oil Spot Price FOB per EIA



Strike price floor would reduce performance incentives the most during the shoulder seasons, which is also when supply is lowest



*“Flexible Response Services (FRS) capability consistently exceeded requirements. While FRS requirements remained steady throughout the year, **offered capability showed seasonal fluctuations, declining during the shoulder seasons (spring and fall)**, when resources tend to take their planned outages, and rising in summer and winter.*

*Only small amounts of Energy Imbalance Reserve (EIR) typically cleared, although volumes fluctuated based on market conditions. **October had the highest level of average EIR clearing due to high generator outages and reduced net interchange**, while July had the lowest level. DA A/S products accounted for a relatively small share of total Energy and Ancillary Services (E&AS) costs in 2025, amounting to a net settlement of \$137.2 million, or about 2% of overall costs.”*

IMM 2025 Annual Markets Report

p. 180

<https://www.iso-ne.com/static-assets/documents/100035/2025-annual-markets-report.pdf>



FirstLight Amendment – Tariff & Filing Letter Language

Amendment to ISO-NE Proposed Changes: Remove Changes to Day-Ahead Ancillary Services Strike Price

- **Restore the language in Section III.1.8.2 and A.8.1.2 to their present form**
i.e., remove ISO-NE proposed redlines related to the Strike Price Floor
- **Replace With Filing Letter Commitment to Improve the Gaussian Mixture Model**
ISO-NE would commit to improve the ability of the Gaussian Mixture Model (“GMM”) to consistently forecast the expected Real-Time Locational Marginal Price of Energy at the Hub (“Expected RTLMP”). While the GMM generally does a good job of evaluating the next day Expected RTLMP, it is generally known that the GMM can have biases under certain conditions, e.g., following abrupt changes in fuel prices.



MEMORANDUM

TO: NEPOOL Participants Committee Members and Alternates

FROM: Sam Regan, NEPOOL Counsel

DATE: June 9, 2026

RE: Consideration of Request for NEPOOL GIS 83D Certificates Rule Changes

At its June 16-18, 2026 meeting, the Participants Committee will be asked to consider an enhancement to the NEPOOL Generation Information System (“GIS”) and a change to the GIS Operating Rules (the “Rules”) to (i) mark Certificates sold under agreements entered into in accordance with Section 83D of the Massachusetts Act Relative to Green Communities¹ (“Section 83D”) with a separate designation and (ii) provide the selling party under those agreements with the ability to designate specific GIS Certificates as being transferred under those Section 83D agreements (the “GIS Changes”). These GIS Changes were requested by Eversource Energy, National Grid, Unitil (collectively the “MA EDCs”) and HQ Energy Services (U.S.) Inc. (“HQUS”).

This item was initially included on the Consent Agenda but a Market Participant End User representative requested it be removed from the Consent Agenda for broader discussion and potential amendment (see End User representative memorandum included with package of material for this item).

Background & Overview of Requested GIS Changes

Under Section 83D, the MA EDCs and HQUS entered into agreements to purchase and sell certain energy and Certificates associated with hydroelectric generation delivered into ISO-NE over new transmission facilities (the “Agreements”). The MA EDCs and HQUS request that, for purposes of tracking the applicable Certificates, the Certificates purchased by the MA EDCs under the Agreements contain a mark designating those Certificates as being transferred under Section 83D. Moreover, the Certificates to be purchased by the MA EDCs under the Agreements could be generated by any of several generating units, and not all Certificates generated by those generating units and imported into ISO-NE would be purchased under the Agreements.

As a result, the typical arrangement of tying a Certificate designation to a specific generating unit for all Certificates created for that generator would not apply to the Certificates purchased under the Agreements because those Certificates could originate from one of 62 different units and not all of the energy generated by those units would be sold under the Section 83D Agreements. In order to address this, the MA EDCs and HQUS request that functionality be

¹ St. 2008, c. 169, as amended.

added to the GIS to allow HQUS to designate the specific Certificates being delivered under those Agreements under Section 83D.²

APX, Inc., the GIS Administrator (“APX”) estimates that implementing the requested changes to the GIS would require 188 development hours at a total cost of \$33,840. These changes would also require a revision to the Rules, which is attached as Appendix A. Under Rule 1.3 of the Rules, changes to the GIS that require 50 hours or more of labor or have an estimated cost to NEPOOL of more than \$30,000 and that in either case are not required to address a change in law or a change in the ISO Tariff must be approved by the Participants Committee.

The NEPOOL GIS Operating Rules Working Group discussed the changes to the GIS and the GIS Rules at a meeting on January 29. The Markets Committee voted to recommend the changes to the Participants Committee at its May 12 meeting, with no opposition and two abstentions registered.

The following form of resolution could be used for Participants Committee action on the Markets Committee’s recommendation to change the GIS:

RESOLVED, that the Participants Committee approves the changes to the NEPOOL Generation Information System (GIS) and the GIS Operating Rules to allow the marking and designation of Certificates sold in accordance with agreements entered into in accordance with Section 83D of the Massachusetts Act Relative to Green Communities, as recommended by the Markets Committee at its May 12, 2026 meeting, together with [such changes as agreed to at this meeting and with] such non-material changes thereto as may be approved after the meeting by the Chair of the Participants Committee.

cc: NEPOOL GIS Operating Rules Working Group

² This request seeks to identify the Certificates that comply with Section 83D and meet the requirements for unit specific imports under the Rules. This request does not relate to determining eligibility of any Certificates under Section 83D, which is determined by the Massachusetts statute.

APPENDIX A

[Attached]

Rule 2.5 Sources of Generation Data

...

- (l) An Account Holder that transfers Certificates to one or more Account Holders in accordance with Section 83D of the Massachusetts Act Relative to Green Communities will notify the GIS Administrator of the specific number of Certificates so transferred to each Account Holder, including the specific number of Certificates from each applicable generating unit registered in the GIS for each calendar month in the calendar quarter for which the Certificates are to be created. The GIS Administrator will designate the Certificates identified by such transferring Account Holder as “Section 83D” Certificates.

...

Rule 2.7 Imports

...

- (u) such generating unit is either (i) eligible under one of the RPS fields, the CES field or the CES-E field listed in Part 2 of Appendix 2.4 or (ii) a hydroelectric or hydropower generating unit or (iii) a nuclear generating unit; or (iv) designated by the seller of Certificates transferred under agreements entered into in accordance with Section 83D of the Massachusetts Act Relative to Green Communities and marked as “Section 83D” Certificates as described in Rule 2.5(l) and as listed in Part 2 of Appendix 2.4;

...

Appendix 2.4

GIS Certificate Fields⁵

...

Massachusetts

Clean Energy Standard for Clean Existing Generation Units (yes/no)

Section 83D (yes/no)

MEMORANDUM

To: NEPOOL Participants Committee

From: William P. Short III for Freedom Companies
Lisa Linowes for Industrial Wind Action Group

Date: June 9, 2026

Re: Proposed Amendment to GIS Motion Regarding Section 83D Certificate Designations

Proposed Amendment

The authors propose that the pending motion be amended as follows (new language highlighted):

Approve proposed changes to the NEPOOL Generation Information System (GIS) and GIS Operating Rules related to marking of Certificates as being transferred under Section 83D of the Massachusetts Act Relative to Green Communities, as recommended by the MC at its May 12-14, 2026 meeting, together with such further non-material changes as may be approved by the Chair of the GIS Operating Rules Working Group; provided that the GIS Working Group (GISWG) is directed to develop and present recommendations regarding reporting and transparency provisions for associated transmission flows and net regional deliveries related to such designated Certificates.

Basis for the Amendment

This memorandum does not challenge Massachusetts' decision to award Clean Energy Standard ("CES") credit to qualifying imports delivered under Section 83D contracts. Rather, it concerns the transparency of the GIS as a regional tracking system.

The motion would create a new GIS designation for Section 83D Certificates and allow sellers to designate specific Certificates as having been transferred pursuant to Section 83D agreements. As a result, stakeholders would be able to identify and track Section 83D transactions within the GIS.

The motion does not provide comparable visibility into the transmission-flow context associated with those transactions.

Since NECEC entered service in January 2026, ISO-NE tie-line data have shown recurring periods of simultaneous imports over NECEC and exports on other Hydro-Québec interfaces, including HQ Phase II and Highgate. (See attached chart.)

For example, during April 2026:

- NECEC imports totaled approximately 509 GWh.
- Exports on HQ Phase II totaled approximately 274 GWh.

As a result, net flows across these interfaces were materially lower than the gross volume imported over NECEC.

The proposed amendment would address this transparency gap by directing the GISWG to develop recommendations regarding reporting and disclosure of associated transmission-flow information. The amendment does not prescribe a specific implementation mechanism. Rather, it recognizes that transparency regarding associated transmission flows should accompany creation of a new Section 83D Certificate designation.

Conclusion

The motion creates a new mechanism for identifying and tracking Section 83D Certificates within the GIS.

The proposed amendment would complement that designation by directing the GISWG to develop recommendations regarding transparency for associated transmission flows and net regional deliveries.

Accordingly, the authors respectfully request adoption of the proposed amendment.

If the amendment is not adopted, the authors oppose approval of the motion in its current form because it creates a new Section 83D Certificate designation without providing comparable transparency regarding the associated transmission-flow context.

ISO New England Public

Monthly Peak Load and Energy Data

2026 - Net Tie Flows (GWh)*	JAN	FEB	MAR	APR	SUM YTD
New Brunswick	116	51	104	66	337
New York-Northern AC Ties	953	770	379	832	2,933
Hydro-Quebec Phase II	7	290	56	-274	79
Hydro-Quebec Highgate	58	71	10	0	139
New York-Cross Sound Cable	-68	-87	-127	-68	-350
New York-Norwalk/Northport	67	51	0	0	118
New England Clean Energy Connect	312	743	820	509	2,384
Total Net Tie Lines (GWh)	1,445	1,889	1,243	1,064	5,641

2026 - Imports (GWh)*	JAN	FEB	MAR	APR	SUM YTD
New Brunswick	119	60	110	81	371
New York-Northern AC Ties	959	770	432	833	2,994
Hydro-Quebec Phase II	225	290	57	30	602
Hydro-Quebec Highgate	60	71	10	0	142
New York-Cross Sound Cable	0	1	0	0	1
New York-Norwalk/Northport	71	53	0	0	124
New England Clean Energy Connect	330	743	820	509	2,402
Total Imports (GWh)	1,764	1,987	1,429	1,454	6,635

2026 - Exports (GWh)*	JAN	FEB	MAR	APR	SUM YTD
New Brunswick	-2	-10	-6	-16	-34
New York-Northern AC Ties	-7	0	-53	-2	-61
Hydro-Quebec Phase II	-218	0	0	-304	-522
Hydro-Quebec Highgate	-2	0	0	0	-2
New York-Cross Sound Cable	-68	-88	-127	-68	-351
New York-Norwalk/Northport	-4	-1	0	0	-5
New England Clean Energy Connect	-18	0	0	0	-18
Total Exports (GWh)	-319	-98	-187	-389	-994

* Positive denotes imports; negative denotes exports

**Due to the difference in calculation methodologies, these values can occur on different days and hours.

All values subject to re-settlement and re-posting.

An Assessment of the Day-Ahead Ancillary Services Market

© ISO New England Inc.
Internal Market Monitor

JUNE 8, 2026



Preface/Disclaimer

The Internal Market Monitor (“IMM”) of ISO New England Inc. (the “ISO”) has prepared this report on the performance and the competitiveness of the Day-Ahead Ancillary Services (DA A/S) Market.

This report fulfills the requirement of Market Rule 1, Appendix A, Section III.A.17.2.5, *Additional Ad Hoc Reporting on Performance and Competitiveness of Markets*:

In furtherance of its function under Section III.A.2 of this **Appendix A**, including without limitation Sections III.A.2.3(e) and (k) therein, the Internal Market Monitor shall perform independent evaluations and prepare ad hoc reports on the overall competitiveness and performance of the New England Markets or particular aspects of the New England Markets, including the competitiveness and performance of a major market design change. The Internal Market Monitor shall have the sole discretion to determine when to prepare an ad hoc report and may prepare such report on its own initiative or pursuant to a request by the ISO, New England state public utility commissions or one or more Market Participants. However, the Internal Market Monitor will report on the competitiveness and performance of any new major market design change within one to three years, respectively, of the effective date of operation of the market design change, or as soon as adequate data becomes available. While the Internal Market Monitor may solicit or receive input of the External Market Monitor, Market Participants and other stakeholders, including New England state public utility commissions, the methodology and criteria used to conduct its independent analysis shall be at the sole discretion of the Internal Market Monitor. The Internal Market Monitor shall describe its methodology and criteria used in an ad hoc report of its significant findings and, if any, recommendations. The Internal Market Monitor shall file with the Commission and post to the ISO’s website a final version of an ad hoc report. Thereafter, the Internal Market Monitor shall continue to report on the competitiveness and performance of any market design change that has been the subject of an ad hoc report in its quarterly or annual reports under Sections III.A.17.2.2 and III.A.17.2.4.

All information and data presented here are the most recent as of the time of publication.

Contents

Preface/Disclaimer	iii
Contents	iv
Figures	vi
Tables	vii
Section 1 Executive Summary	8
Section 2 Introduction and Assessment Scope	15
Section 3 Market Design Overview	17
3.1 Day-Ahead Ancillary Services Market.....	18
3.1.1 Requirements and Products	18
3.1.2 Settlement	20
3.1.3 Offer Formulation	22
3.1.4 Mitigation	23
3.2 Day-Ahead Energy Market.....	24
3.2.1 Forecast Energy Requirement.....	25
Section 4 Market Costs	27
4.1 Settlement Costs	28
4.2 Incremental Costs.....	29
4.3 Cost Benchmarking.....	32
Section 5 Assessment of Cost Drivers	34
5.1 System and Market Conditions.....	34
5.2 Impact of New Market Constraints	40
5.2.1 Flexible Response Services	40
5.2.2 Forecast Energy Requirement.....	41
5.3 FRS Costs Examined.....	43
5.3.1 Opportunity Costs.....	43
5.3.2 Offer Costs	44
5.3.3 Key Drivers and Outcomes for the 12 Highest-Cost DA A/S Days	45
Section 6 Assessment of Market Competitiveness	48
6.1 Market Participation	49
6.1.1 Flexible Response Services	49
6.1.2 Energy Imbalance Reserves	52
6.1.3 Unoffered Capability	53
6.2 Market Structure	54

6.3 Offer Behavior	59
Section 7 Mitigation Performance	65
Section 8 GMM Performance.....	70
8.1 Expected Real-time LMP.....	70
8.2 Expected Closeouts	72
Section 9 Market Performance Metrics	75
9.1 Price Convergence	75
9.2 Out-of-Market Actions	77
9.3 Impact on NCPC (Uplift)	78
9.4 Revenues Source Mix and Implications	82
Section 10 Reliability Outcomes	84
10.1 Commitment Differences	84
10.2 Fuel Scheduling and Management.....	87
10.3 Resource Availability and Performance.....	89
Section 11 Survey Results	91

Figures

Figure 1-1: Day-Ahead Ancillary Services Cost Estimates and Drivers	9
Figure 3-1: Conceptual Representation of DA A/S Market Reforms	17
Figure 3-2: DA A/S Clearing by Technology and Offered Fuel.....	20
Figure 3-3: Average Hourly DA A/S Clearing Prices by Product and Month.....	21
Figure 3-4: Distribution of Real-Time Energy Prices	22
Figure 3-5: The Impact of FER on Day-Ahead Energy Market Clearing.....	26
Figure 4-1: Cumulative Incremental Change in Market Costs	31
Figure 5-1: Impact of Opportunity Costs on FRS Clearing Prices	43
Figure 5-2: “Marginal” Offer Price for Total 30 Requirement with Offer Components	45
Figure 6-1: Offered FRS Capability relative to Requirements, Ex-ante.....	50
Figure 6-2: Offered FRS Capability relative to Requirements, Ex-post.....	51
Figure 6-3: Cleared EIR MW.....	52
Figure 6-4: Percentage of Hours with at least One Pivotal Supplier (Ex-post) in the DA A/S Market	58
Figure 6-5: Payoff Diagram	60
Figure 7-1: DA A/S Mitigations	66
Figure 7-2: Conduct Test Failures Across FRS Products	67
Figure 7-3: Offers Relative to Mitigation Values.....	67
Figure 7-4: Percent of Hours with Impact Test Failure	68
Figure 8-1: Probability Integral Transform (PIT) Histogram, All Hours.....	71
Figure 8-2: PIT Histogram, Winter Hours.....	72
Figure 8-3: Actual and Expected Closeouts, Cumulative	73
Figure 9-1: Day-Ahead vs. Real-Time LMP Convergence	76
Figure 9-2: RAA and Manual Capacity and Locational Commitments	78
Figure 9-3: Estimated NCPC Cost of Averted RAA Commitments.....	81
Figure 9-4: Net Revenue by Technology Type	83
Figure 11-1: Participant Understanding of the Market (Survey).....	92
Figure 11-2: Inputs to DA A/S Offers (Survey).....	93

Tables

Table 4-1: DA A/S Settlements (\$ millions).....	28
Table 4-2: FER Settlements (\$ millions)	29
Table 4-3: Estimated Change in Market Costs	30
Table 4-4: Comparison of Incremental DA A/S Costs: High-Cost Days to All Other Days.....	32
Table 4-5: Day-Ahead Ancillary Services Costs in ISO-NE Compared to NYISO	33
Table 5-1: Estimated Incremental Costs from DA A/S (ISO-NE Impact Analysis)	35
Table 5-2: Estimated Change in Market Costs from DA A/S, 2019-2021 (ISO-NE IA).....	36
Table 5-3: Differences in System Conditions and Competitive Offer Components	37
Table 5-4: Estimated Change in Market Costs from DA A/S (IMM “IA Refresh”)	38
Table 5-5: Estimated Change in Market Costs with only the FRS Constraints	40
Table 5-6: Summer Highest-Cost DA A/S Days.....	46
Table 5-7: Winter Highest-Cost DA A/S Days	46
Table 6-1: DA A/S Market Concentration Ratios	55
Table 6-2: DA A/S Market Herfindahl-Hirschman Indices.....	56
Table 6-3: DA A/S Market Pivotal Supplier and RSI Statistics.....	57
Table 6-4: Comparison to Outcomes with Competitive Offers plus Sharpe Ratio Risk Premia	62
Table 6-5: Comparison to Outcomes with Competitive Offers plus CVaR Risk Premia	64
Table 10-1: Energy gap statistics pre- and post-DA A/S implementation, in MW.....	85
Table 10-2: Day-Ahead Generation by Startup plus Notification Time.....	86
Table 10-3: Economic Long Lead-Time Commitments With and Without DA A/S	86
Table 10-4: Gas scheduling pre- and post-DA A/S implementation	88
Table 10-5: Total Percentage of Accredited Capacity Out-of-Service.....	89

Section 1

Executive Summary

The Day-Ahead Ancillary Services Market introduced the most significant reforms to New England's wholesale energy markets in over twenty years. Under this design, the Day-Ahead Market jointly clears energy and Day-Ahead Ancillary Services (DA A/S) to meet expected next-day load and operating reserve requirements. The initiative was launched on February 28, 2025.

This report evaluates the competitiveness and performance of the DA A/S design during its first year of operation. While the analysis is based on a limited period, it provides a comprehensive assessment of market outcomes and will be further supplemented by ongoing quarterly reporting on market performance and a required three-year full performance review.¹

The report begins with an overview of the market design, followed by detailed analysis of market costs, cost drivers, and comparisons with the New York ISO market. We then assess market competitiveness, mitigation effectiveness, and market performance metrics, including reliability impacts. The final section presents results from an IMM survey of market participants, offering qualitative data and additional insight into how the design reforms have been experienced in practice.²

In our assessment, we conclude that DA A/S costs are consistent with competitive market participant behavior. However, competitiveness does not necessarily translate into efficient outcomes. In February 2026, we put forward a set of targeted recommendations to improve the cost-effectiveness of the DA A/S design based on our ongoing monitoring and assessment work.³ These include refinements to the Strike Price methodology, adjustments to the Forecast Energy Requirement (FER), and a review of contingency-response related performance parameters affecting the ten- and thirty-minute reserve requirements. One of these changes (the latter) was implemented on May 1, 2026, while the ISO is currently working with stakeholders on detailed design changes for the remaining two recommendations.⁴ We continue to believe that these changes will meaningfully improve cost-effectiveness and overall market performance.

A number of key findings emerge from this one-year assessment.

¹ Appendix A, Market Rule 1, I.A.17.2.5 requires the IMM to assess the competitiveness of major market design changes within one year (subject to sufficient data) and to evaluate market performance within three years.

² The IMM appreciates the time and thoughtful responses provided by the market participants who participated in the survey.

³ ISO-NE Internal Market Monitor (David Naughton), "Recommended Changes to the Day-Ahead Ancillary Services Market," memo, February 4, 2026, https://www.iso-ne.com/static-assets/documents/100032/2026_02-imm-memo-with-daas-recommendations.pdf

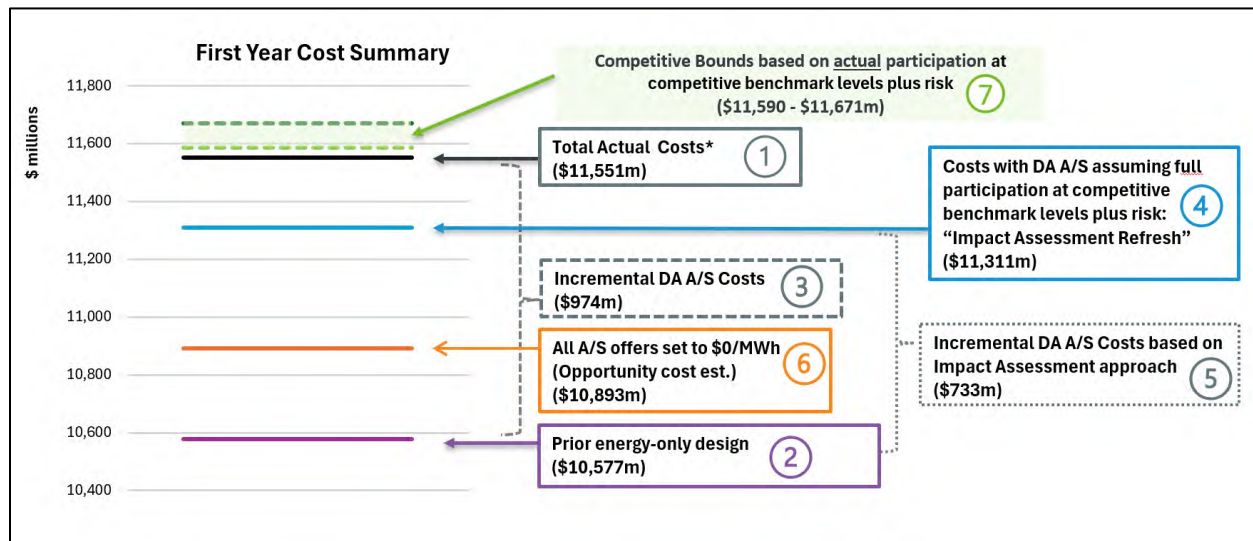
⁴ The report does not quantify the impact of these changes; backcast-based estimates have been provided by the ISO to stakeholders as part of ongoing design discussions. See ISO New England, "Day-Ahead Ancillary Services Post-Implementation Adjustments," presentation to NEPOOL Markets Committee, May 12–14, 2026, https://www.iso-ne.com/static-assets/documents/100035/a06_mc_2026_05_12-14_daas_post_implementation_adjustments_presentation.pdf

Estimated Incremental Costs of DA A/S Totalled \$974 Million in the First Year, with 12 Days Accounting for 50%

The first twelve months of DA A/S operation corresponded to a period of elevated fuel and energy costs, and several multi-day periods of exceptionally high demand and extreme weather events that had not been experienced in some years. Overall, energy and ancillary services (E&AS) costs from March 2025 through February 2026 totaled **\$11,500 million** (\$11.5 billion), the highest since 2022 and the second highest since 2008 in nominal terms.⁵

A core part of this assessment includes a series of simulation studies to evaluate DA A/S costs and identify key cost drivers and assess competitive outcomes. The figure below summarizes total E&AS costs from these simulations. The key values from the simulation studies are labeled with a number and referenced in the narrative below to facilitate interpretation.

Figure 1-1: Day-Ahead Ancillary Services Cost Estimates and Drivers



*Based on simulated DA A/S market rules used as the benchmark for counterfactual comparisons. Total costs modeled in the simulation include LMP, FER, DA Flexible Response Services and EIR net costs, and the cost of real-time incremental energy.

First, we compare outcomes under the new co-optimized energy and ancillary services market to those under the prior energy-only design to estimate incremental costs of the design. Total simulated E&AS costs amounted to **\$11,551 million** ①, closely matching actual costs and reflecting strong model benchmarking performance throughout the study period. We estimate that costs under the prior energy-only market would have been **\$10,577 million** ②, meaning that total incremental costs were **\$974 million** ③, about 9% higher than the prior energy-only design, or \$8.23/MWh of load served.

⁵ Actual total energy and ancillary services costs include day-ahead and real-time energy, reserve, regulation, and NCPD costs.

DA A/S costs were concentrated in a relatively small number of stressed operating days. Specifically, 12 days accounted for roughly 50% of incremental costs, with a five-day winter storm event (Winter Storm Fern) contributing about 40%, and a single day (January 27, 2026) accounting for 18%. These “**Top 12 Days**” are particularly important to analyze because they reflect periods when reliability risks are elevated and strong price signals and performance incentives are most critical. Accordingly, we assess market competitiveness and performance during these days in greater detail throughout the report.

Higher-than-Expected DA A/S Costs Primarily Reflect Changes in Market and System Conditions

DA A/S costs were significantly higher than those estimated in ISO-NE’s original Impact Assessment (IA), which used 2019–2021 data and estimated incremental costs of **\$140 million** (approximately 3% of total E&AS costs). Significantly different market fundamentals and system conditions during the 2025/26 period—including higher natural gas prices, increased energy price volatility, shifts in the supply mix, and more frequent stressed conditions—put upward pressure on costs.

To model these effects collectively, we conducted an “IA Refresh” using the same methodology as the original IA, which assumes full participation and competitive offer pricing (including risk premiums). When developing the IA, the ISO made assumptions about participant behavior and the nature of the competitive environment. Like many economic studies, ISO-NE premised assumptions on market participation on profit-maximizing behavior under competitive conditions. Consistent with that framework, participants were assumed to offer their full physical capability at the estimated cost of meeting the DA A/S obligation. This approach provides a full-participation, competitive-equilibrium benchmark reflecting an expected long-run market outcome.

Under these assumptions, total costs would have been **\$11,311 million** ④, implying incremental DA A/S costs of **\$733 million** ⑤ (\$5.66/MWh). Updated market conditions therefore explain roughly 75% of the observed incremental costs of \$974 million. The remaining **~\$240 million** in incremental costs (not explained by updated market/system conditions) is primarily attributable to lower participation and higher offer prices than benchmark levels.

Higher-than-Expected Costs also Reflect Differences Relative to Assumed Market Behavior and Highlight the Role of Opportunity Costs in Price Formation

In practice, participation has been lower and offer prices higher than assumed in the IA, resulting in tighter supply conditions, higher cross-product opportunity costs, and a higher marginal cost of meeting energy and ancillary service requirements.

Under these conditions, opportunity costs play a key role in price formation by ensuring that resources are indifferent between providing energy and ancillary services in the co-optimized market. Although difficult to quantify opportunity costs precisely, simulation results show that even if all DA A/S historically-offered capability were offered at \$0/MWh, total E&AS costs would be **\$10,893 million** ⑥, indicating that the system would still incur **\$316 million** (\$2.67/MWh) in incremental costs to satisfy FER and FRS constraints.

Ultimately, market participation decisions depend on a myriad of factors, including commercial strategy considerations, physical and operational constraints, and perceptions of market risk.

Importantly, our survey results suggest market complexity also played a role in participation decisions. Some participants indicated that they adjusted their offer behavior over time as they became more familiar with the market, but many indicated that they wanted additional training to enhance their understanding and comfort with specific market features. These findings are consistent with the broader analysis in this report, which shows that risk, uncertainty, and market design features play a significant role in shaping offer behavior and market outcomes.

- ➔ We recommend that the ISO provide additional and ongoing technical training related to DA A/S to facilitate and accelerate market participation.

DA A/S Costs were Consistent with Competitive Market Participant Behavior

Our competitiveness analysis indicates that DA A/S market outcomes were broadly consistent with competitive behavior. Specifically, we find that:

- Participation levels have generally not raised **physical withholding** concerns that would impact overall competitive cost estimates. Participation levels continue to trend upwards with market experience. While there has generally been sufficient offered capability to meet the load and reserve requirements, we find that the level of participation is particularly impactful on market costs and prices on high load/stress days. The IMM continues to consult with participants regarding their participation levels to guard against potential physical withholding.
- There is also no indication of impactful **economic withholding** on overall costs. Observed market costs were consistent with simulated costs using competitive offer benchmarks, indicating that offer levels from participating resources were broadly consistent with competitive, risk-adjusted offer behavior. To assess whether market outcomes are consistent with competitive offer behavior, we conducted two simulations in which DA A/S offers are set at IMM benchmark levels, differing only in how the risk premium is defined. Together, these risk methodologies provide a range of competitive outcomes: one based on a return-per-unit-of-risk metric (Sharpe) and one based on a more conservative tail-risk measure (conditional Value at Risk). Market costs of **\$11,551 million** ① are consistent with, and even slightly below, the IMM's **competitive bounds of \$11,590 and \$11,671 million** ②, although that result is driven largely by a small number of high-cost days; for most of the year, costs were closely aligned with the IMM's competitive benchmarks.
- **DA A/S offer mitigation** occurred infrequently and effectively addresses circumstances where offers both materially exceeded benchmark expectations and had a measurable effect on clearing prices. One notable exception arises when price impact thresholds fell below \$3/MWh, which occur during times when system conditions were generally unstressed and market power is not a concern. Almost thirty-percent of mitigations occurred under these conditions. The ISO plans to address as part of their DA A/S market enhancements work in 2026 by incorporating a \$3/MWh price impact floor, a sensible measure that will address these observed instances of over-mitigation.
- DA A/S markets exhibit moderate concentration, and some realized outcomes—particularly for DA TMSR—show tight post-clearing reliance on a relatively small set of suppliers when capability is assessed after commitment. These “ex-post” measures can

help identify intervals that warrant closer monitoring. However, they likely overstate the extent of market power. In the day-ahead market, clearing reflects the joint satisfaction of multiple requirements, so there is not a single marginal unit that can be isolated; changes in any binding constraint generally affect the dispatch and reserve provision of multiple units and this inherent substitutability can mitigate market power concerns.⁶

The Strike Price and Expected Closeout Cost Calculator (the “GMM”) Showed Systematic Bias

The ISO’s Gaussian Mixture Model (GMM) model for determining key DA A/S values—specifically the strike price and expected closeout—exhibited systematic bias in its first year of operation, understating real-time LMPs on average. This under-forecasting bias is evident in actual outcomes falling frequently in the upper tail of the predictive distribution and carried through to expected closeout charges, which were also systematically understated relative to actual closeout charges.

These findings have two important implications. First, when the model produces Strike Prices and expected closeout values that are below prevailing market expectations, the IMM may need to adjust mitigation values to offset this misalignment, potentially leading to higher offer prices and increased day-ahead market costs.⁷ Indeed, the IMM performed such adjustments during many high-stress days. Second, implementing a Strike Price floor—consistent with our recommendation to better align the strike price with the short-run marginal costs of resources providing ancillary services—offers a meaningful secondary benefit by eliminating forecasting errors below the marginal cost of a combustion turbine.

- ➔ Even with the IMM’s recommended strike price adjustments, we encourage the ISO to continue to invest in its modeling tools and processes to ensure that expected real-time energy prices and closeout costs better track prevailing market conditions.

Evidence of Reliability Benefits is Promising but Preliminary

We have considered stakeholder interest in the reliability benefits of DA A/S, particularly in light of higher-than-expected costs. Accordingly, we developed a framework that combines empirical analysis with survey responses to evaluate changes in resource performance and commitment patterns. Given that this assessment is based on a single year of operation, the results should be interpreted with caution, and the framework will continue to evolve as additional data and stakeholder feedback become available.

The DA A/S design incorporates features that support reliability—most notably transparent pricing and stronger performance incentives—but participant behavior also reflects the combined influence of energy, capacity, and ancillary services market incentives. Therefore several observed

⁶ In addition, efficient market outcomes need not include surplus TMSR capability, and the market can re-optimize commitment and reserve awards in response to offers.

⁷ The relationship between strike price levels and market outcomes is nuanced and requires further study. In particular, while lower strike prices relative to prevailing market conditions increase expected closeout costs and likely increases overall day-ahead costs, however this effect is at least partially offset by higher realized closeout costs.

reliability effects remain preliminary and cannot yet be treated as causal, and therefore care should be taken in attributing observed performance improvements to DA A/S alone.

Early indications are encouraging but mixed.

- **Outage rates:** Combustion turbine availability has improved, reflected in lower outage rates which have fallen from 18% to 11% for resources taking on DA A/S obligations.
- **Natural gas procurement:** We measured if gas-fired generators scheduled additional natural gas day-ahead to meet DA A/S positions, in the context of stronger incentives to be prepared to perform. We did not find a measurable change in the amount of natural gas scheduled to meet real-time needs, even during winter months when intraday gas procurement is more uncertain. About 97% of natural gas needs continue to be scheduled day-ahead.
- **Operational changes:** On the other hand, survey responses indicate that DA A/S awards influence operational decisions; 71% of respondents reported taking actions in response to awards, most commonly procuring fuel.
- **Day-ahead commitments:** More commitments of long-lead time resources occur under DA A/S, with no commitments made through the out-of-market next-day Reserve Adequacy Analysis (RAA) process; under DA A/S such commitments face financial obligations and stronger performance incentives, and create additional responsive capability in real-time.

Potential Cost Implications for the Capacity Market and Uplift

DA A/S has introduced a market-based revenue stream for flexible, fast-start combustion turbines, which comprise the majority of cleared resources, and therefore has implications for how costs are recovered across wholesale markets. First-year DA A/S revenues averaged approximately \$3.50/kW-month fleetwide, compared to about \$1.30/kW-month under the former Forward Reserve Market in 2023 and 2024. These additional revenues reduce the reliance on out-of-market uplift payments and contribute to a shift in cost recovery toward market-based mechanisms. They also have implications for capacity market pricing by offsetting a portion of the “missing money” reflected in competitive capacity offers and, over time, are expected to be incorporated into Net Cost of New Entry estimates, placing downward pressure on future capacity market costs.

Absent DA A/S, additional commitments of long-lead-time generation would likely have been required after the day-ahead market to meet expected load and reserve requirements. As a result, DA A/S may reduce NCPC by limiting reliance on post-day-ahead (RAA) commitments. However, the magnitude of these reductions is highly uncertain and sensitive to assumptions about operator behavior. Estimated savings are bounded at approximately \$35 million annually, with more realistic outcomes likely significantly lower (e.g., roughly \$11 million under peak conditions).

Continued Monitoring and Openness to Refinements Will Be Important

The new market design has been in operation for only one year. Given the magnitude of the design change, it is not surprising that refinements are being considered based on early experience to improve or balance cost-effectiveness. While we do not include additional design recommendations in this assessment, further changes may be warranted for ISO and stakeholder

consideration as more data become available and our monitoring and assessment work continue. Future analysis will help determine whether the patterns observed in the first year reflect long-run outcomes or transitional effects.

Section 2

Introduction and Assessment Scope

In fulfillment of its obligations under the ISO-NE tariff, the Internal Market Monitor (IMM) has prepared this report on the performance and the competitiveness of the Day-Ahead Ancillary Services (DA A/S) Market. This report is filed with the Federal Energy Regulatory Commission pursuant to Appendix A, Market Rule 1, I.A.17.2.5, which requires the IMM to assess the competitiveness of major market design changes within one year (subject to sufficient data) and to evaluate market performance within three years.

This report goes beyond a narrow assessment of “competitiveness” and instead evaluates the first year of operation of the DA A/S market and the broader day-ahead market. A subsequent review will be conducted in 2028, after the DA A/S design has been in place for three years.

Prior to this report, the IMM has already put forward a set of targeted recommendations to improve aspects of the DA A/S design.⁸ These include refinements to the strike-price methodology, adjustments to the Forecast Energy Requirement (FER), and a review of parameters affecting the quantity of reserve procurement. This report does not attempt to quantify the impact of these recommended changes. Rather, the analysis is intended to inform these recommendations and to highlight areas where adjustments may improve certain aspects of design performance.

The implementation of DA A/S represents one of the most significant changes to the ISO New England market design in recent years. Prior to DA A/S, the day-ahead market committed resources to satisfy operating reserve requirements but did not create financial obligations nor compensate resources for these ancillary services capabilities. Instead, reserve providers were primarily compensated for these capabilities through the Forward Reserve Market (FRM) or infrequent real-time reserve pricing. In addition, the process for managing differences between day-ahead schedules from physical resources and expected real-time operating conditions relied on actions that took place after the day-ahead market clearing was complete.

That prior energy-only design created several challenges. First, because the day-ahead market was not transparently procuring operating reserves, resource owners were not explicitly aware that the ISO was relying on them for these services in its operating plan. Second, the value of reserve capability was not clearly reflected in day-ahead market prices. Third, when the set of resources committed through the day-ahead market proved insufficient to satisfy reliability needs, the ISO relied on out-of-market actions to ensure reliability.

The DA A/S reforms were developed to address these limitations, but, at the same time, these reforms have made certain costs more visible through marginal pricing principles. Under the prior market structure, some of the costs associated with maintaining reserve capability and operational

⁸ The memo titled *Recommended Changes to the Day-Ahead Ancillary Services Market* is available here: https://www.iso-ne.com/static-assets/documents/100032/2026_02-imm-memo-with-daas-recommendations.pdf

flexibility were reflected through mechanisms such as the FRM or uplift payments rather than through explicit day-ahead ancillary service payments.

Under the new design, reserve procurement costs are incorporated more directly into market settlements. As a result, one of the most prominent features of the first year of DA A/S has been the magnitude of the increase in energy and ancillary services costs associated with the initiative. Stakeholders have focused on these costs and raised a central question: what benefits does the market produce in return?

We start to answer that question in this report. Because a new market design that visibly increases market payments will inevitably be judged against its costs, the evaluation in this report places emphasis on benefits as well as costs. However, some of the expected benefits of DA A/S — particularly those associated with increased participant incentives and improved system preparedness — are inherently more difficult to measure than the costs. Market payments can be directly observed in settlement data, while benefits are not as easily captured. For this reason, the report evaluates a broader set of metrics that are closely tied to the objectives of the reform. These include changes in fuel scheduling, day-ahead commitment, and unit availability and performance.

The report is organized around three broad analytical questions.

1. **What was the incremental cost of this initiative?** This includes a review of energy and ancillary services settlements, a structured assessment of incremental cost, and a benchmarking to ancillary services costs in the New York ISO market.
2. **What factors drove these costs?** This includes an analysis of the role of system conditions and participant behavior. The analysis of participant behavior includes a review of market participation, an evaluation of the market structure and offer behavior, and an assessment of mitigation effectiveness.
3. **What benefits has this initiative produced?** This includes a review of the market's performance as well as a high-level evaluation of preliminary reliability benefits.

To address these questions, the report uses several complementary methods, including analysis of observed market outcomes, simulation-based counterfactual analysis, and survey evidence from market participants.

The first year of any major market reform will inevitably involve adaptation. Participants are still learning the details of the market, the ISO is accumulating experience with the new design, and the data from a single year may reflect system conditions that are not representative of long-run outcomes. For these reasons, this report should be understood as a first-year review rather than a final assessment of the long-run performance of the market.

Section 3

Market Design Overview

The Day-Ahead Ancillary Services Market represents a set of reforms to the day-ahead market with the objectives of procuring the ancillary service capabilities necessary to meet reliability requirements, pricing those capabilities in a transparent manner, and compensating the resources that provide those capabilities.⁹

These market reforms impacted both the energy and ancillary services markets. The introduction of the DA A/S market was accompanied by a significant alteration to the energy market with a new market constraint that ensures that enough physical

capability is procured day-ahead to satisfy the ISO's load forecast. Importantly, the DA A/S market and the existing day-ahead energy market collectively form the day-ahead market, which jointly clears energy and ancillary services in a co-optimized process that determines the optimal allocation of energy and ancillary services to satisfy the system's requirements.

Glossary

DA A/S: The ancillary services products that are procured in the DA A/S market

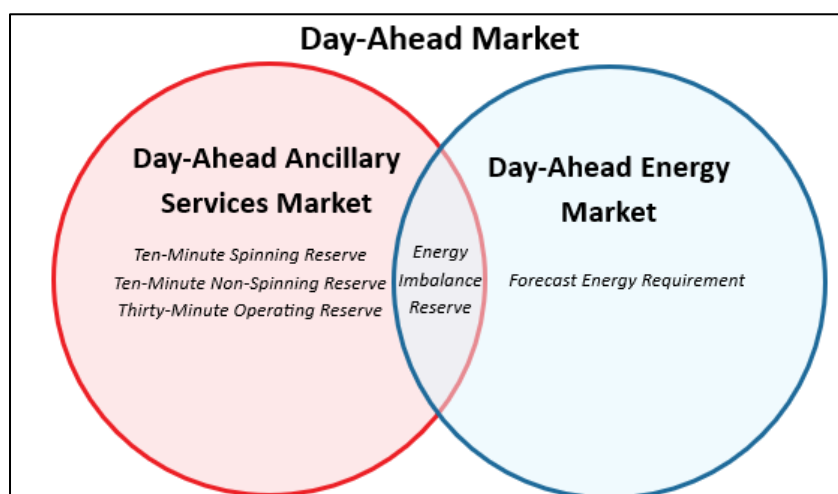
DA A/S market: The day-ahead ancillary services market

DA energy market: The day-ahead energy market

DA market: The jointly optimized DA energy and DA A/S market

A conceptual representation of the DA A/S market reforms is depicted in Figure 3-1 below.

Figure 3-1: Conceptual Representation of DA A/S Market Reforms



⁹ See Page 16 of the testimony of Dr. Matthew White in support of DA A/S contained within the ISO's filing to FERC, which is available here: https://www.iso-ne.com/static-assets/documents/100004/rev_to_est_jointly_optimized_day-ahead_mkt_for_energy_and_ancillary_services.pdf.

An overview of these market reforms is provided below in order to set the groundwork for the discussion of market costs and performance that follows.

3.1 Day-Ahead Ancillary Services Market

The DA A/S market is a voluntary market in which the ISO procures certain ancillary service capabilities one day in advance of when they are needed. Resources that have these capabilities can receive compensation for them in return for taking on a financially-binding obligation that is linked to the real-time LMP.

3.1.1 Requirements and Products

Flexible Response Services

Flexible Response Services (FRS) provide the fast-starting and fast-ramping capability needed for the ISO to respond quickly to large supply losses. These services correspond to operating reserves and are based largely on the system's largest contingencies, consistent with analogous requirements in the real-time market.¹⁰ These requirements are:

- The **Ten-Minute (Total 10) Reserve Requirement** is the amount of 10-minute reserve capability (spinning or non-spinning) that is required by the system. It is based on the system's first contingency multiplied by a non-performance factor, which changed from 120% to 115% on May 1, 2026.¹¹
- The **Ten-Minute Spinning Reserve (TMSR) Requirement** represents the amount of the Total 10 requirement that must be met through spinning reserves. This amount is generally set at 25% of the Total 10 requirement but can range between 25% to 100%.
- The **Total Reserve (Total 30) Reserve Requirement** is the total amount of 10-minute and 30-minute reserve capability required by the system. The amount in excess of the Total 10 reserve requirement is generally 50% of the system's second contingency plus an additional amount known as Replacement Reserves, which varies between 160 MW and 180 MW depending on the season.

To help satisfy these requirements, resources may make offers for the following products:¹²

- **Ten-Minute Spinning Reserve (TMSR):**
 - This is capability that is synchronized to the grid and capable of responding within ten minutes.

¹⁰ For more information about the determination of operating reserve requirements, see ISO-NE Operating Procedure No. 8: https://www.iso-ne.com/static-assets/documents/rules_proceeds/operating/isone/op8/op8_rto_final.pdf

¹¹ This change took effect for the operating day of May 1, 2026. For more information about the motivation behind this change, see: https://www.iso-ne.com/static-assets/documents/100034/a05_reserve_nonperformance_factor_updates.pdf.

¹² There are some exceptions to the general reserve capability descriptions provided here. For information about the calculation of reserve capability, see Section III.1.7.19.2 of the ISO-NE Tariff, available here: https://www.iso-ne.com/static-assets/documents/2014/12/mr1_sec_1_12.pdf.

- This reserve product can be used to satisfy the TMSR, Total 10, and Total 30 requirements.
- **Ten-Minute Non-Spinning Reserve (TMNSR):**
 - This is capability that is not synchronized to the grid but can start and respond within ten minutes.
 - This reserve product can be used to satisfy the Total 10 and Total 30 requirements.
- **Thirty-Minute Operating Reserve (TMOR):**
 - This is capability that may or may not be synchronized to the grid but is capable of responding within thirty minutes.
 - This reserve product can be used to satisfy the Total 30 requirement.

Energy Imbalance Reserves

Energy Imbalance Reserve (EIR) provides reserve capability used to help meet the load forecast. Physical supply resources with 60-minute reserve capability can be compensated by clearing EIR awards. The market clearing engine procures EIR to help satisfy the **Forecast Energy Requirement (FER)**, which ensures that expected next-day demand is met through a combination of day-ahead energy awards on physical resources and EIR awards.¹³

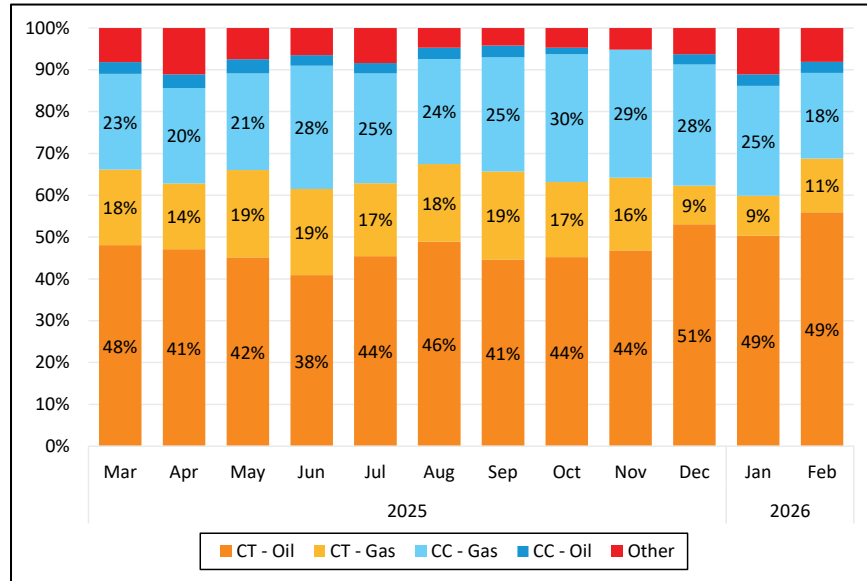
Observed DA A/S Clearing

Combustion turbine (CT) and combined-cycle (CC) resources accounted for most DA A/S clearing during the first year of the market. These resources were primarily fueled by natural gas and oil.¹⁴ Figure 3-2 shows monthly DA A/S clearing by technology and fuel type, expressed as shares of total clearing (MWh), with each column summing to 100%.

¹³ The FER is discussed in much more detail in Section 3.2.

¹⁴ While some of these resources can run on multiple fuels (i.e., are dual-fuel capable), when they do run, they generally run exclusively on one fuel. For these “dual-fuel” resources, we use the fuel underlying the energy offer for a specific hour.

Figure 3-2: DA A/S Clearing by Technology and Offered Fuel



Combustion turbines dominated DA A/S clearing each month over this period. Oil-fired CTs typically accounted for roughly 40–50% of cleared awards, while gas-fired CTs contributed an additional 10–20%. CT resources supplied nearly all TMSR awards in every month and also made meaningful contributions to TMOR and EIR clearing.

Combined-cycle units offering on gas also represented a substantial share of DA A/S clearing, generally in the range of 20–30% each month. These units were the primary suppliers of TMSR throughout the year.

Other resource types had only a limited role. Pumped-storage hydro and pondage hydro were the only other resource types to account for more than one percent of cleared DA A/S awards during the first year of the DA A/S Market.

3.1.2 Settlement

DA A/S awards are settled using a two-part call option settlement design. The first settlement depends on the day-ahead market; resources that receive a DA A/S award earn a credit at the ancillary service clearing price and the MWh quantity of awards. The second settlement depends on the real-time market; resources with a DA A/S award incur a closeout charge as follows:

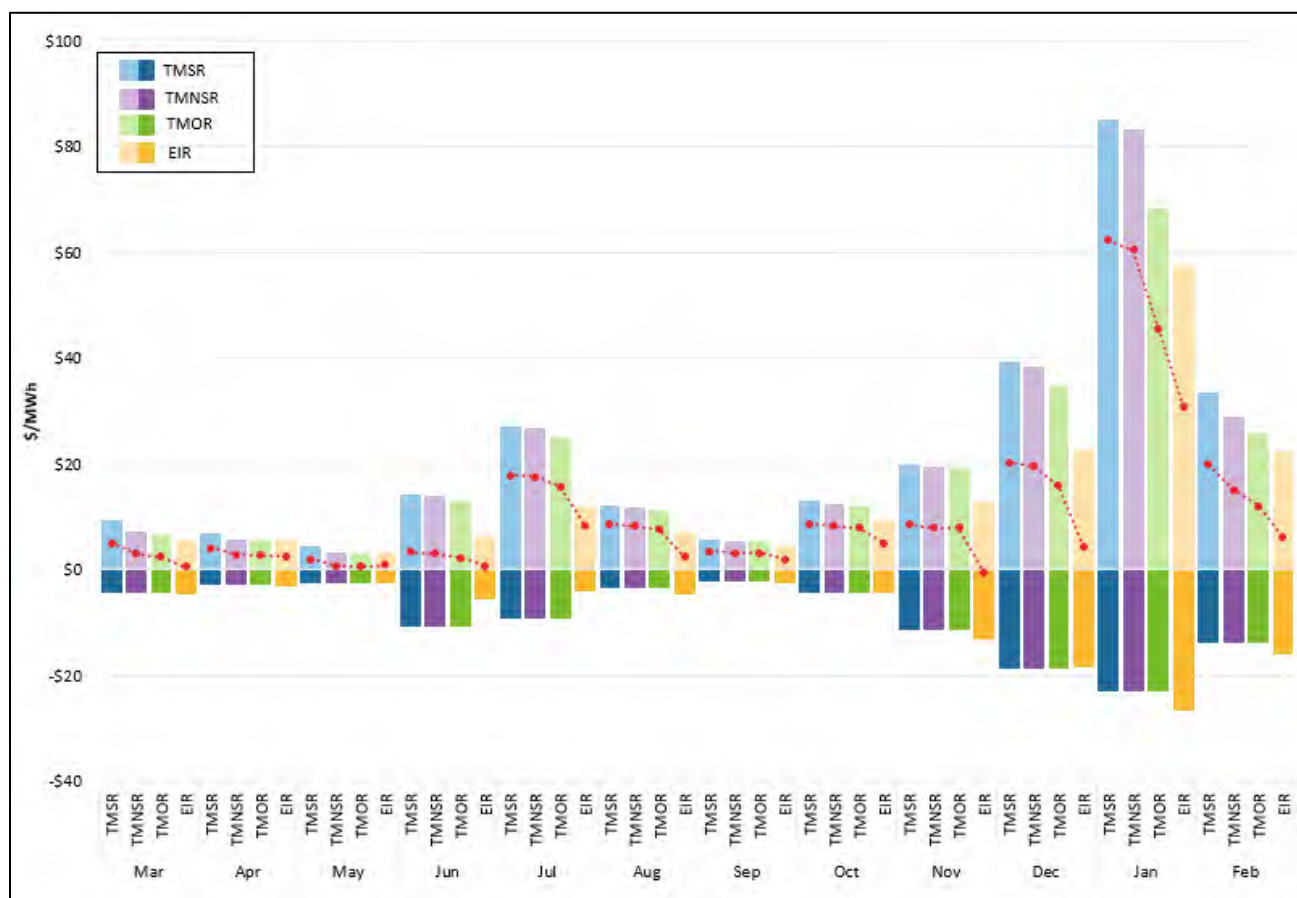
$$\text{Closeout charge} = \text{Award MW} \times \max(LMP_{Hub}^{RT} - \text{Strike Price}, 0)$$

This equation is an important part of the DA A/S market design as it creates a new financial link to the real-time energy market for a resource with a DA A/S award. If the real-time Hub LMP exceeds the strike price (often denoted by K), then resources with a DA A/S award incur a closeout charge. However, if the real-time Hub LMP is less than the strike price, then resources with DA A/S awards incur no charge. The current design sets the hourly strike price at the expected real-time Hub LMP plus a \$10 adder.

Observed DA A/S Clearing Prices

Figure 3-3 below captures this two-part settlement over the first year of DA A/S. This figure shows the average hourly DA A/S clearing prices as positive values and realized closeout charges as negative values by product and month.¹⁵ This figure also depicts the clearing price less the realized closeout charge, which we refer to as the *net* clearing price, with a red circle.

Figure 3-3: Average Hourly DA A/S Clearing Prices by Product and Month



The DA A/S clearing prices were highest in the summer (specifically, July 2025) and winter months (specifically, December 2025, January 2026, and February 2026). These are months when the power system tends to experience more stressed conditions, which can lead to higher and more volatile energy prices. We provide additional information on several acute periods during the first year of DA A/S throughout this report in order to provide additional insight into the drivers of the higher costs observed during these months.

Given their price formation mechanics, the clearing prices of the three FRS products (TMSR, TMNSR, and TMOR) were closely aligned, while the clearing price for EIR (i.e., the Forecast Energy

¹⁵ The EIR values depicted in this figure are the average hourly values for only the hours when cleared EIR MWs were greater than zero.

Requirement Price or FERP) was lower nearly every month.¹⁶ In general, realized closeouts were lower than DA A/S clearing prices, resulting in positive net clearing prices for all products in every month with the exception of EIR in November 2025.

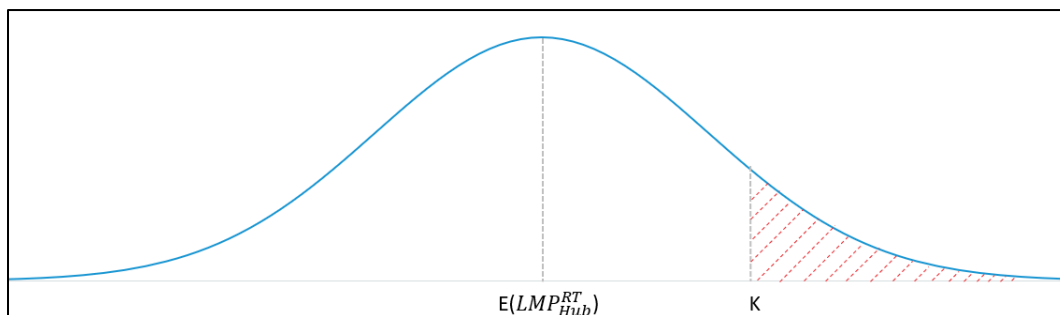
3.1.3 Offer Formulation

The settlement structure described above is foundational to the formulation of a DA A/S offer. This is because, by virtue of receiving a DA A/S award, a resource incurs an (otherwise avoidable) cost in expectation due to the closeout charge. Under the DA A/S design, this cost is referred to as the **Expected Closeout (charge)**. The expected closeout is a critical element of the design because it underpins a competitive DA A/S offer and forms the basis of the mitigation framework.

Conceptually, the expected closeout exists because the real-time LMP could fall between a range of possible values depending on the actual system conditions that occur. For example, lower-than-expected loads could lead to reduced real-time LMPs, while the unexpected trip of a large generator could lead to heightened real-time LMPs. The former scenario is unlikely to create a closeout charge for a resource with a DA A/S award but the latter scenario might.

A simplified graphical representation of this idea is presented in Figure 3-4 below. The x-axis in this figure depicts all the possible values of the real-time LMP that could occur and the blue line defines the likelihood of each of those values; more extreme values of the real-time LMP are less likely to occur (as indicated by the lower level of the blue line at those values), and less extreme values are more likely to occur (as indicated by the higher level of the blue line at those values). This figure depicts the expected value of the real-time LMP as $E(LMP_{Hub}^{RT})$ and the strike price as K. All values of the real-time LMP above K would lead to a closeout charge; this range is indicated in the figure with the dashed red line.

Figure 3-4: Distribution of Real-Time Energy Prices



A central goal of the design is to create strong incentives for resource owners to be prepared to cover their DA A/S positions with physical generation (consistent with a covered call framework).

¹⁶ Specifically, FRS clearing prices “cascade up.” This means, for example, that the shadow price of the Total 30 requirement will appear not only in the TMOR clearing price, but will also “cascade up” into the TMNSR and TMSR clearing prices because these products also help satisfy this requirement. The result is the following relationship between clearing prices for the FRS products: $CP_{TMSR} \geq CP_{TMNSR} \geq CP_{TMOR}$.

Otherwise, the resource effectively buys out of its position at the market's replacement cost reflected in the real-time LMP, potentially incurring net losses.

In addition to the expected closeout, which is relevant to all resource types, there are two other components to a competitive DA A/S offer as defined by the ISO. The first, which is called the **Avoidable Input Cost (AIC)**, represents input energy-related costs incurred by a subset of DA A/S providers (gas and energy storage) that could otherwise be avoided but for the DA A/S award. And the second is a **risk premium**, which captures the uncertainty in net revenues associated with clearing a DA A/S award.

3.1.4 Mitigation

To safeguard competitiveness, DA A/S incorporated a new mitigation framework.¹⁷ This framework is designed to reduce price-impactful exercises of market power while preserving room for competitive offers that reflect reasonable expected values for closeout costs, avoidable input costs and risk. It utilizes the same conduct-and-impact approach that is commonly employed to mitigate market power throughout New England's wholesale markets. The conduct test identifies offers that may be inconsistent with competitive behavior, while the impact test assesses the effect of those flagged offers on market clearing prices. If a DA A/S product offer fails the conduct test, and the impact test fails in any hour, the submitted offer price is replaced during market clearing with a reference price that is intended to represent a competitive offer.¹⁸ This reference price, referred to as a **Benchmark Level** under the DA A/S design, is equal to the sum of the expected closeout and, as applicable, the AIC.

¹⁷ For more information about DA A/S mitigation, see Section III.A.8 of the ISO-NE Tariff, available here: https://www.iso-ne.com/static-assets/documents/2014/12/mr1_sec_1_12.pdf.

¹⁸ One unique aspect of the DA A/S mitigation design is that a DA A/S product offer is mitigated in a given hour if the offer fails the conduct test in that hour and there is a price impact failure in any hour of that same day (i.e., the impact test failure does not need to occur in the same hour as the conduct test failure for DA A/S mitigation to occur).

The conduct test compares the DA A/S offer price to an estimate of an upper-end competitive price. This latter price is referred to as the **Conduct Test Threshold Price**, and all offer prices that exceed this value are flagged for possible mitigation. The conduct test threshold price is defined as the sum of:

1. 200% of the expected closeout charge;¹⁹ and
2. 150% of the AIC.²⁰

The impact test used for the DA A/S market determines whether DA A/S offers that are flagged by the conduct test have a material effect on increasing DAM clearing prices beyond acceptable levels.²¹ For this purpose, materiality is defined by the **Impact Test Threshold**, which is set at 150% of the median difference between (1) the conduct test threshold prices for all Day-Ahead Ancillary Services offers submitted for the offer-hour and (2) the Benchmark Levels for all Day-Ahead Ancillary Services offers submitted for the offer-hour.²² In the majority of hours, this means the threshold is 150% of the expected closeout.

3.2 Day-Ahead Energy Market

Prior to DA A/S, the market clearing outcomes in the day-ahead market did not always align with expected real-time conditions. For example, less physical energy supply could clear than was expected to be needed in real time.²³ When that happened, there was a day-ahead “energy gap” (i.e., the amount of day-ahead energy awards on physical resources was less than the expected real-time load.)

¹⁹ The 200% multiplier was intended to give suppliers reasonable room to reflect risk premiums, forecasting error in estimated closeout values, and expected differences between Day-Ahead and Real-Time outcomes. The ISO concluded that this level captured a reasonable range of competitive offer behavior without materially weakening market power protections. For additional discussion on this topic, please see pages 90-92 of the testimony of Dr. Parviz Alivand in support of DA A/S contained within the ISO’s filing to FERC, which is available here: https://www.iso-ne.com/static-assets/documents/100004/rev_to_est_jointly_optimized_day-ahead_mkt_for_energy_and_ancillary_services.pdf.

²⁰ The 150% multiplier was intended to allow for resource-specific variations in fuel and charging costs, as well as potential inaccuracies in the ISO’s standard cost formulas. The ISO concluded that this level provided a reasonable allowance for competitive cost variation while maintaining an effective conduct screen. For additional discussion on this topic, please see pages 101-102 of the testimony of Dr. Parviz Alivand in support of DA A/S contained within the ISO’s filing to FERC, which is available here: https://www.iso-ne.com/static-assets/documents/100004/rev_to_est_jointly_optimized_day-ahead_mkt_for_energy_and_ancillary_services.pdf.

²¹ This evaluation is performed for each hour using all resources that submitted DA A/S offers for that hour, and it measures whether conduct-test-flagged offers increase any Day-Ahead Market price, including the DA LMP and each of the four DA A/S clearing prices.

²² The 150% factor provides a 50 percent buffer above the base threshold measure to account for the limitations of using a single mitigation run and to avoid unnecessary mitigation of offers that may be flagged in that run but, on their own, would not materially affect market prices. Based on its market simulations, the ISO concluded that this level appropriately balances avoiding over-mitigation and preventing under-mitigation. For additional discussion on this topic, please see pages 104-111 of the testimony of Dr. Parviz Alivand in support of DA A/S contained within the ISO’s filing to FERC, which is available here: https://www.iso-ne.com/static-assets/documents/100004/rev_to_est_jointly_optimized_day-ahead_mkt_for_energy_and_ancillary_services.pdf.

²³ Physical energy supply refers to generators, demand response resources, and imports.

3.2.1 Forecast Energy Requirement

To address this “energy gap,” the day-ahead market introduced a new constraint—the **Forecast Energy Requirement (FER)**—which requires sufficient capability from physical resources to meet the ISO’s load forecast. The market satisfies the FER through a combination of day-ahead energy awards on physical resources and EIR awards.²⁴

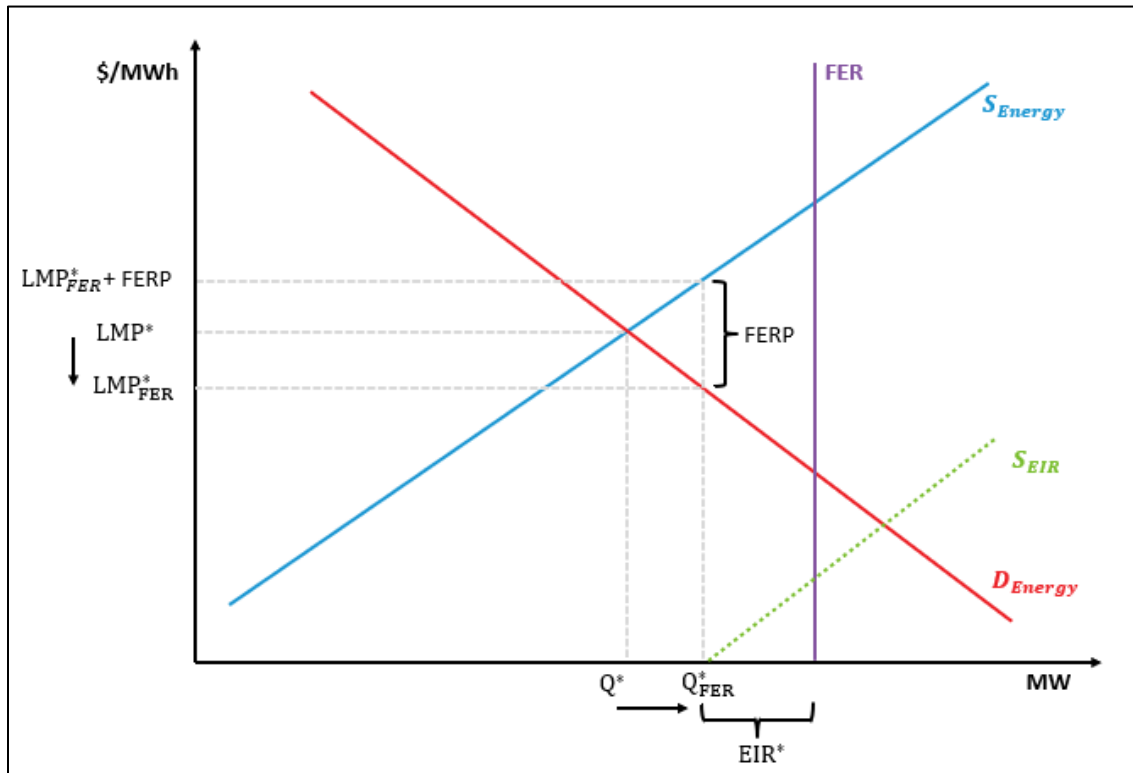
For their contribution to satisfying the FER constraints, physical supply resources with day-ahead energy awards and EIR awards are paid the **FER Price (FERP)**. Notably, the addition of the FER constraint fundamentally changed the paradigm for energy compensation to physical resources in the day-ahead market; physical resources are now compensated for their energy via a combination of the LMP and FERP, whereas prior to DA A/S they received energy compensation solely via the LMP. The **FER credit** represents the payment to physical supply resources with day-ahead energy awards for their contribution to satisfying the FER constraint. The FER credit is allocated as a charge primarily to real-time load obligation (RTLO) on a pro-rata basis.²⁵

A simplified graphical representation of the impact that the FER has on day-ahead energy market clearing is presented in Figure 3-5 below.

²⁴ For more information about Energy Imbalance Reserves (EIR), see Section 3.1.1.

²⁵ For more information on how the FER credit is charged, see Section III.3.2.1(q)(4)(iii) of the ISO-NE Tariff: https://www.iso-ne.com/static-assets/documents/2014/12/mr1_sec_1_12.pdf

Figure 3-5: The Impact of FER on Day-Ahead Energy Market Clearing



Prior to DA A/S, the intersection of the energy supply curve (blue line) and energy demand curve (red line) determined the quantity of cleared energy (Q^*) and the clearing price for that energy (LMP^*). With the introduction of the FER (purple line), the market clearing changes. The market clearing engine must find a combination of energy on physical resources and EIR (dashed green line) to satisfy the FER. In the figure above, the market now clears a higher quantity of energy (Q_{FER}^*) and the remainder of the FER is satisfied via cleared EIR (EIR^*) such that $Q_{FER}^* + EIR^* = FER$. **Importantly, the LMP with the FER included (LMP_{FER}^*) is lower than the LMP without it (LMP^*).** However, physical resources with energy awards as well as resources that clear EIR awards receive the FERP because of their contribution to satisfying the FER.²⁶ As such, physical resources with energy awards now receive $LMP_{FER}^* + FERP$ as energy market compensation, which covers the marginal cost of energy supply.

²⁶ In this example, the FERP is set by energy supply and demand rather than by EIR, although that can and frequently does occur.

Section 4

Market Costs

This section presents the settlement costs associated with DA A/S in its first year as well as an estimate of the incremental costs of DA A/S relative to an energy-only design intended to replicate the day-ahead market design prior to DA A/S. As such, this analysis distinguishes between *settlement costs* and *incremental economic cost*.

Settlement costs measure the credits and charges created by the DA A/S design, including DA A/S credits and closeout charges, and FER credits and charges. Although these items determine who pays and who receives money, they do not, by themselves, measure the incremental cost of the new market design because the same market design change also affects other settlement-related factors (e.g., day-ahead LMPs).

For this reason, we also present a simulation-based estimate of incremental economic cost. Importantly, the simulations do not measure all offsetting or interactive effects, including the retirement of the Forward Reserve Market (FRM), potential reductions in NCPC, future effects on capacity-market offer behavior and Net CONE, or changes in investment and retirement incentives. Consequently, the simulation-based results can be best understood as measures of the incremental day-ahead and deviation-settlement effects of introducing the FER and FRS requirements, not as a full cost-benefit analysis of the initiative.

Key Takeaways

During the first year, net DA A/S payments totaled \$261.7 million (\$2.21/MWh of load served) and were heavily concentrated in winter months, which accounted for roughly 60% of the total. FER credits were much larger at approximately \$1 billion (\$8.49/MWh), also showing strong seasonality with nearly two-thirds occurring in winter. Therefore, total year one settlement payment/costs totaled over **\$1.25 billion**, or \$10.70/MWh of load served.

Simulation results indicate that the implementation of the DA A/S market increased total incremental costs relative to the prior day-ahead design by about **\$974 million** in its first year (\$8.23/MWh of load served), a lower amount than settlements costs primarily reflecting the interplay between the FERP and (lower) DA LMP. A small number of high-cost days drove a disproportionate share of this increase: just 12 days accounted for roughly 50% of incremental costs, with a five-day winter storm event alone contributing about 40%, and a single day (January 27, 2026) responsible for 18%.

Net costs for the Flexible Response Services in New England averaged \$2.10/MWh of load, which was higher than the costs of similar products in a comparable market (NYISO). These higher prices in New England reflect both system characteristics (e.g., high reserve requirements relative to load) and design features, in particular the DA A/S call-option settlement design, which is intended to enhance reliability through stronger performance incentives than a forward sale construct as exists in New York.

4.1 Settlement Costs

The DA A/S products represent a small percentage of overall energy and ancillary services (E&AS) costs.²⁷ This can be seen in Table 4-1, which shows the *net* settlements for the DA A/S products by season for the first year.^{28,29}

Table 4-1: DA A/S Settlements (\$ millions)

DA A/S	Spring 2025	Summer 2025	Fall 2025	Winter 2026	Total
DA TMSR (net)	\$3.7	\$16.6	\$8.5	\$45.6	\$74.4
DA TMNSR (net)	\$6.3	\$26.1	\$16.1	\$65.1	\$113.6
DA TMOR (net)	\$2.9	\$13.3	\$7.8	\$36.3	\$60.3
EIR (net)	\$0.2	\$1.4	\$1.7	\$10.1	\$13.4
Total (net)	\$13.1	\$57.4	\$34.1	\$157.1	\$261.7
Total E&AS Costs	\$1,284	\$2,346	\$1,610	\$6,261	\$11,500
% Total E&AS Cost	1%	2%	2%	3%	2%

Net DA A/S payments totaled \$261.7 million during the first year, representing about 2% of total E&AS costs over the period, or \$2.21/MWh of load served.³⁰ TMNSR payments represented the largest component at \$113.6 million, followed by TMSR at \$74.4 million, and TMOR at \$60.3 million. EIR payments were relatively small at \$13.4 million in total, contributing little to overall costs. Importantly, while the total DA A/S payments are highly seasonal—with Winter 2026 accounting for the majority these payments (60%)—they tended to move in-line with overall E&AS markets costs, generally accounting for 1 to 3% of these overall E&AS market costs.

FER credits have accounted for much larger share of total E&AS costs throughout the first year. This can be seen in Table 4-2 below, which shows total FER credits by quarter.

²⁷ Total energy and ancillary services costs include day-ahead and real-time energy, reserve, regulation, and NCPC costs.

²⁸ The months included in each season are: Spring: Mar-May, Summer: Jun-Aug, Fall: Sep-Nov, Winter: Dec-Feb

²⁹ For the purposes of calculating the settlement value of the DA A/S market, we sum the initial credit and the closeout charge to calculate a final *net* payment/charge.

³⁰ Load served, or Net Energy for Load, during the one-year period totaled 118,400 GWh, or 13,516 MW on average per hour.

Table 4-2: FER Settlements (\$ millions)

	Spring 2025	Summer 2025	Fall 2025	Winter 2026	Total
FER Credit	\$74.4	\$122.2	\$166.9	\$641.6	\$1,005.1
Total E&AS Costs	\$1,284	\$2,346	\$1,610	\$6,261	\$11,500
% Total E&AS Cost	6%	5%	10%	10%	9%

FER credits totaled approximately \$1 billion during the first year of DA A/S, accounting for approximately 9% of total E&AS costs over the period, or \$8.49/MWh of load served. The average annual FER price was \$7.13/MWh (including all hours, even when the FERP was zero). Like DA A/S payments, FER credits vary by season with the largest value occurring in winter; FER credits during the winter accounted for \$641.6 million, or roughly 64% of total FER credits. FER credits represented between 5-6% of total E&AS costs during spring and summer before climbing to 10% for both the fall and winter. The increase during the fall was related to the high level of generator outages and a reduction in net interchange in the day-ahead market,³¹ while the winter increase was related to increased payments during a multi-day period of stressed system conditions.

4.2 Incremental Costs

We performed market simulations to better understand the incremental impact of DA A/S on market outcomes relative to the day-ahead market (DAM) design that was in place prior to March 1, 2025. To perform these simulations, we used an in-house market simulation tool that both replicates the logic of the day-ahead market (DAM) that exists in production today and also provides the flexibility to modify constraints and other key inputs.^{32,33}

The simulations indicate that the initiative increased total day-ahead and deviation-settlement costs relative to the prior energy-only design, but the increase appears through different settlement components than the underlying economic driver may suggest. In the full DA A/S case, the large share of the incremental payments appears as FER credits and net DA A/S credits. In a no-FER simulation, similar underlying FRS-procurement costs tend to appear through higher DA LMPs instead.

³¹ For more in-depth coverage of this period, see the IMM's Fall 2025 Quarterly Markets Report, available here: <https://www.iso-ne.com/static-assets/documents/100032/2025-fall-quarterly-markets-report.pdf>.

³² Importantly, while the IMS benchmarks very well against the GE market clearing engine (MCE) that is used in production at ISO-NE, the simulation results should be viewed as indicative rather than exact. The market simulator captures the main co-optimized commitment, scheduling, constraint, and pricing logic that has been benchmarked to production-market outcomes, but it does not reproduce every production-engine feature.

³³ Due to simulation-related constraints, December 5, 2025, and January 3, 2026, are not reflected in any of the simulation results.

Incremental Cost of DA A/S

In order to estimate the impact of DA A/S on market costs, the following scenarios were simulated:

- 1) **No DA A/S:** a scenario in which all DA A/S constraints (FER, FRS) are ‘turned off.’ This scenario is intended to reflect the pre-March 2025 day-ahead market.³⁴
- 2) **DA A/S:** a scenario in which all DA A/S constraints are ‘turned on.’ This scenario is intended to reflect the current day-ahead market.

The following table provides a high-level comparison of these two scenarios.

Table 4-3: Estimated Change in Market Costs

Category	No DA A/S (\$M)	DA A/S (\$M)	Delta (\$M)	Delta (%)
DA Energy	\$10,437	\$11,153	\$716	6.9%
<i>LMP</i>	\$10,437	\$10,127	-\$309	-3.0%
<i>FER Price</i>	\$0	\$1,026	\$1,026	
DA A/S	\$0	\$261	\$261	
<i>Credits</i>	\$0	\$453	\$453	
<i>Closeouts</i>	\$0	-\$192	-\$192	
Total Charges/Credits	\$10,437	\$11,415	\$978	9.4%
Cost of Incremental RT Energy	\$140	\$136	-\$4	-2.9%
Total Cost/Revenue Change	\$10,577	\$11,551	\$974	9.2%

We estimate that DA A/S resulted in an increase of \$974 million (9.2%) in total costs over the first year. The majority of the incremental cost increases are in the form of higher day-ahead energy market payments, where we estimate an increase of \$716 million relative to the ‘No DA A/S’ scenario. While energy payments via the day-ahead LMP decreased by \$309 million relative to the ‘No DA A/S’ scenario, this is more than offset by a \$1,026 million FER credit.³⁵ Net payments to the new DA A/S awards (\$261 million) represent all of the remaining estimated cost increase. The simulations indicate very little change in incremental real-time energy purchases between the two scenarios.³⁶

³⁴ The IMM did *not* adjust energy offers in this scenario in any way (e.g., there was no adjustment to reflect the way participants with FRM obligations were required to offer in the real-time market under that market design).

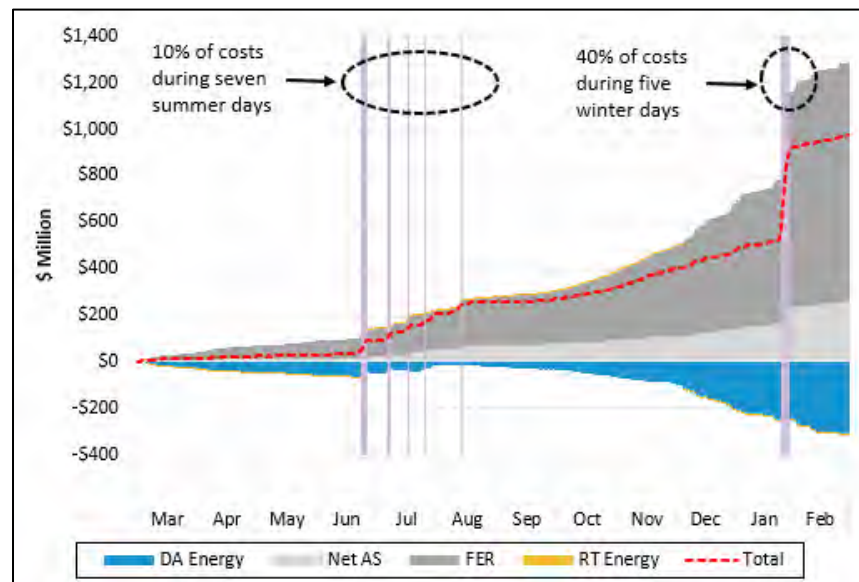
³⁵ See Figure 3- and the associated text for an explanation of this impact this design has on the day-ahead LMP.

³⁶ We calculate the cost of incremental real-time energy as (real-time load obligation – day-ahead load obligation) * real-time LMP, mimicking the deviation settlement logic. These costs can differ because one scenario may clear more energy supply in the day-ahead market relative to another and therefore need to procure less energy supply in real-time market. Importantly, we assume no changes in the real-time LMP between the two scenarios, which is a conservative assumption in hours where DA A/S improved the day-ahead operating plan and reduced the likelihood of moving up a steep real-time supply curve.

High-Cost Days

It is important to call out the outsized impact that a small set of high-cost days had on the incremental costs of DA A/S during its first year. This can be seen in Figure 4-1, which shows the cumulative total incremental change in market cost broken down by cost component over the first year of DA A/S.

Figure 4-1: Cumulative Incremental Change in Market Costs



We found that 12 days, most of which were associated with multi-day periods of stressed system conditions, accounted for approximately 50% of incremental costs of DA A/S in its first year (we note these in the figure above with light purple bars). These 12 days include a five-day period from January 25, 2026, to January 29, 2026, that coincided with Winter Storm Fern, as well as the following seven days in Summer 2025: June 23 through June 25,³⁷ July 7, July 17, July 25, and August 13. We estimate that one day alone, January 27, 2026, accounted for 18% of the incremental DA A/S costs and that the five-day period between January 25, 2026, to January 29, 2026, accounted for 40% of these incremental costs.

To provide some idea of the impact of these high-cost days on incremental costs, we present Table 4-4, which shows the estimated incremental DA A/S costs for only the 12 highest-cost days within the year as well as the costs for all other days of the year. For reference, the table also shows the full year costs (in gray).

³⁷ The three-day period in June was characterized by hot and humid leading to very high peak loads.³⁷ Events during this period culminated on June 24 when the grid experienced capacity scarcity conditions (CSC). For more coverage on this period, see the IMM's Summer 2025 Quarterly Markets Report, available here: <https://www.iso-ne.com/static-assets/documents/100029/2025-summer-quarterly-markets-report.pdf>.

Table 4-4: Comparison of Incremental DA A/S Costs: High-Cost Days to All Other Days

Category	Incremental Cost (\$M) <i>12 Highest-Cost Days</i>	Incremental Cost (\$M) <i>All Other Days</i>	Incremental Cost (\$M) <i>Complete Year</i>
DA Energy	\$386	\$331	\$716
<i>LMP</i>	\$44	-\$353	-\$309
<i>FER Price</i>	\$342	\$684	\$1,026
DA A/S	\$93	\$169	\$261
<i>Credits</i>	\$134	\$319	\$453
<i>Closeouts</i>	-\$41	-\$151	-\$192
Total Charges/Credits	\$478	\$500	\$978
Cost of Incremental RT Energy	\$11	-\$15	-\$4
Total Cost/Revenue Change	\$489	\$485	\$974

Day-ahead energy costs represent the majority of the incremental costs for both the 12 highest-cost days (\$368 million of \$489 million, or 79%) and all the other days (\$331 million of \$485 million, or 68%). Notably, while we see the \$684 million increase in FERP-based energy payments for the other days being offset by a \$353 million reduction in LMP-based payments, we see the \$342 million dollar increase in FERP-based energy payments for the 12 highest-cost days associated with an *increase* in LMP-based payments of \$44 million. Additionally, we see a higher percentage of the DA A/S credits being offset by closeouts in the other days (\$151 million of \$319 million, or 47%) than we do for the 12 highest-cost days (\$41 million of \$134 million, or 31%).

4.3 Cost Benchmarking

In this section, we compare day-ahead reserve costs for ISO-NE against those for the New York Independent System Operator (NYISO), which has comparable loads and reserve requirements. Importantly, while both New England and New York procure ancillary services through a co-optimized market-based mechanism, there are important design differences: ISO-NE utilizes a call-option settlement approach based around the real-time price of energy, while NYISO uses a forward sale settlement approach, in which day-ahead reserve positions are settled against real-time reserve prices.³⁸

Day-ahead reserve costs for ISO-NE and NYISO are shown in \$/MWh of load in Table 4-5 below, alongside metrics that illustrate the comparability of the two regions.

³⁸ For example, if a NYISO generator cleared day-ahead reserves at \$10/MWh but did not provide reserves in real time when reserve prices were \$2/MWh, the reported net day-ahead reserve cost would be \$8/MWh (\$10/MWh - \$2/MWh). This includes scenarios when the generator did not provide real-time reserves because it was dispatched up for energy.

Table 4-5: Day-Ahead Ancillary Services Costs in ISO-NE Compared to NYISO

Concept	ISO-NE	NYISO
DA Reserve Costs,^{39,40} \$/MWh of Load	\$2.10	\$1.39⁴¹
Average Load, MW	13,516	17,329
Largest Contingency,⁴² MW	1,261	1,310
Largest Contingency, % Share of Load	9%	8%

When measured on a \$/MWh of load basis, ISO-NE features higher day-ahead reserve costs than NYISO, with a premium of roughly \$1/MWh of load. While FER credits are not directly accounted for in the \$2.10/MWh of load, the FER constraint indirectly impacts this total as it contributes to overall scarcity in the day-ahead market. Based on counterfactual simulations, the ISO-NE day-ahead reserve cost would have been \$1.82/MWh of load in the absence of the FER constraint.⁴³ This indicates that the ISO-NE reserve premium is largely a function of market design. The call-option settlement approach in ISO-NE is designed to provide stronger real-time performance incentives, and the premium for these incentives must be weighed against their reliability benefits.⁴⁴

³⁹ The *DA Reserve Cost* for ISO-NE represents the net FRS costs (i.e., the FRS credits less the realized closeout charges).

⁴⁰ The reserve cost data for NYISO were provided by Potomac Economics. The products included in this calculation are 10-minute, 30-minute, and spinning reserves. We thank Potomac for their data contributions.

⁴¹ Note that \$1.39/MWh of load represents the *Gross* DA reserve costs for NYISO. This is the sum of DA reserve credits, and ignores scenarios where resources might be dispatched up to provide energy and therefore buy back real-time reserves in the two-settlement system. *Net* reserve costs would deduct the costs of purchasing real-time reserves in these scenarios, and would be a useful comparison to the ISO-NE FRS credits less closeout charges. To bound this estimate, we also calculate the difference between NYISO day-ahead reserve prices and real-time reserve prices, regardless of whether assets were truly buying back real-time reserves or not. This yields a lower-bound estimate of \$0.48/MWh of load. We estimate NYISO net day-ahead reserve costs to fall between \$0.48/MWh-\$1.39/MWh; in any scenario, ISO-NE FRS products come at a price premium when compared to NYISO day-ahead reserves.

⁴² The *Largest Contingency* for NYISO was estimated based on technical documentation ([Link](#)) alongside public information on generator sizes.

⁴³ See Section 0 for more information on the counterfactual simulation that does not include the FER,

⁴⁴ See Section 10 for a discussion of the reliability benefits observed over the first year of DA A/S.

Section 5

Assessment of Cost Drivers

In this section we explore the impact that changes in system conditions and observed participant behavior have had on DA A/S costs. We also attempt to disentangle the relationship between reliability requirements (i.e., FRS requirements, FER) to better understand the cost drivers during the first year of this new market design.

Key Takeaways

We find that changing system conditions and differences between assumed and actual market behavior explain a large percentage of the observed cost increase relative to the ISO's 2023 DA A/S Impact Assessment, which was an important component of the market design process.

Specifically, we find that an update of the ISO's 2023 Impact Assessment, which assumes full participation and competitive offer formulation, would have resulted in incremental costs of \$733 million based on actual data from the first year of DA A/S. Again, a small number of high-stress days disproportionately influenced results: just 13 days accounted for roughly half of total incremental costs, and without them, DA A/S impacts would have been closer to original expectations, underscoring the impact of system stress events on overall DA A/S costs.

We also find that the FRS constraints are the primary underlying driver of incremental costs: absent the FER constraint, roughly \$613 million (about 65%) of total incremental DA A/S costs would persist. The addition of the FER constraint largely changes the clearing prices in which these costs manifest, rather than their root cause.

Opportunity costs have played a role in price formation although it is difficult to precisely quantify their overall impact. However, simulation results show that even if all historically-offered DA A/S capability were offered at \$0/MWh, the system would still incur \$316 million (\$2.67/MWh) in incremental costs to satisfy FER and FRS constraints.

5.1 System and Market Conditions

System and market conditions have changed in meaningful ways since ISO-NE brought the market reforms associated with DA A/S through the stakeholder process and ultimately filed the design changes with the Federal Energy Regulatory Commission (FERC) in October, 2023.⁴⁵ These changes, which include higher natural gas prices, more extreme weather events, and changes in the supply mix, have applied upward pressure on both energy and ancillary service costs.

Additionally, market participation levels and offer prices are materially different from the assumptions made by ISO-NE in their Impact Analysis (IA) work to estimate indicative costs for DA

⁴⁵ The ISO's filing to FERC is available here: https://www.iso-ne.com/static-assets/documents/100004/rev_to_est_jointly_optimized_day-ahead_mkt_for_energy_and_ancillary_services.pdf.

A/S.⁴⁶ In practice, participation has been lower and offer prices higher than was assumed in the IA. These differences have resulted in tighter market supply conditions, high cross-product opportunity costs, and ultimately a higher marginal cost of meeting both energy demand and operating reserve requirements.

Given these differences, the IMM conducted a “refresh” of the IA (which we refer to as the “IA Refresh”) to better understand what the costs of DA A/S might look like under the same full participation and competitive offer assumptions used in the original IA but based on actual data from the first year of the initiative.

The Original IA

In order to capture a range of market conditions, the original IA was performed over a three-year historical period from January 1, 2019, to December 31, 2021. ISO-NE premised market participation and offer price assumptions in the IA on a model of profit-maximizing behavior under competitive conditions. Consistent with that framework, participants were assumed to offer their full physical capability at an estimated competitive cost of meeting the obligation.

The estimated incremental costs associated with DA A/S from the IA are presented as totals and as percentages of total E&AS costs by year in Table 5-1 below.⁴⁷

Table 5-1: Estimated Incremental Costs from DA A/S (ISO-NE Impact Analysis)

Year	Incremental Costs (\$M)	E&AS Costs (\$M)	% E&AS Costs
2019	\$127	\$4,207	3.0%
2020	\$104	\$3,704	3.4%
2021	\$188	\$6,189	3.0%
Average	\$140	\$4,490	3.1%

The IA estimated that DA A/S costs would have averaged \$140 million per year from 2019 to 2021, representing about 3.1% of total E&AS costs. While total E&AS costs varied meaningfully by year, the IA results indicated that DA A/S costs would remain a relatively small and stable share of the overall market.

A more granular summarization of the IA results is presented in Table 5-2 below. This table compares average actual market values from the three-year period (2019-2021) against estimated market values assuming DA A/S had been in place for the same three-year period.

⁴⁶ For more information on the IA, see ISO-NE’s presentation titled *Day-Ahead Ancillary Services (DASI)* from the April 11-13, 2023, NEPOOL Markets Committee meeting, available here: https://www.iso-ne.com/static-assets/documents/2023/04/a07a_mc_2023_04_11-13_dasi_design_r1.pdf

⁴⁷ It is important to note that ISO-NE presented the estimated DA A/S costs relative to total wholesale market costs, which includes Forward Capacity Market (FCM) and transmission costs. We present the estimated DA A/S costs relative to just energy and ancillary services costs as this is our common way to “standardize” costs throughout the document.

Table 5-2: Estimated Change in Market Costs from DA A/S, 2019-2021 (ISO-NE IA)

Category	No DA A/S (\$M)	DA A/S (\$M)	Delta (\$M)	Delta (%)
DA Energy	\$4,405	\$4,588	\$183	4.2%
<i>LMP</i>	\$4,405	\$4,462	\$58	1.3%
<i>FER Price</i>	\$0	\$125	\$125	
DA A/S	\$0	\$22	\$22	
<i>Credits</i>	\$0	\$90	\$90	
<i>Closeouts</i>	\$0	-\$69	-\$69	
Total Charges/Credits	\$4,405	\$4,609	\$205	4.6%
Cost of Incremental RT Energy	\$104	\$40	-\$65	-62.0%
Total Cost/Revenue Change	\$4,509	\$4,649	\$140	3.1%

In the ISO's IA, the increase in markets costs occurred primarily in the day-ahead energy market where costs increased by \$183 million (4.2%). Meanwhile, DA A/S costs were estimated to add only \$22 million to market costs, with \$90 million of DA A/S credits being offset by \$69 million in closeout charges. Notably, the IA estimated a significant reduction (62%) in real-time energy payments.⁴⁸

The “Refreshed” Impact Assessment

System conditions and competitive offers changed considerably between the 2019-2021 period used by the ISO for its impact analysis and the first year of DA A/S. Some of the relevant changes are listed in Table 5-3 below.

⁴⁸ This reduction is likely the result of a “market response” assumption that the ISO incorporated into their simulation work. The ISO assumed that lower day-ahead LMPs under the new design would induce additional priced demand bids, increasing day-ahead cleared energy and supporting price convergence with expected real-time LMPs. The IA therefore added additional energy demand bids to the simulation. This assumption is best understood as a long-run equilibrium response, not as evidence that such behavior was expected to occur in the first year. However, this action increased the amount of demand cleared day-ahead, resulting in smaller real-time deviations and therefore smaller real-time charges/credits. For more information about this modeling assumption, See Page 84 of the testimony of Ben Ewing in support of DA A/S contained within the ISO's filing to FERC, which is available here: https://www.iso-ne.com/static-assets/documents/100004/rev_to_est_jointly_optimized_day-ahead_mkt_for_energy_and_ancillary_services.pdf.

Table 5-3: Differences in System Conditions and Competitive Offer Components

Index	(1/1/2019 – 12/31/2021) Average	(3/1/2025 – 2/28/2026) Average	Delta (%)
DA Gas Price⁴⁹ (\$/MMBtu)	\$3.24	\$6.82	110.5%
DA Hub LMP (\$/MWh)	\$33.48	\$71.44	113.4%
DA Load Forecast (MW)	13,151	13,019	-1.0%
Summer Peak Load⁵⁰ (MW)	25,095	26,586	5.9%
Winter Peak Load⁵¹ (MW)	19,512	20,221	3.6%
Competitive Offer⁵² (\$/MWh)	\$10.00	\$12.78	27.8%
Expected Closeout (\$/MWh)	\$3.20	\$7.74	141.9%
AIC (\$/MWh)	\$0.48	\$3.35	597.9%
Risk Premium (\$/MWh)	\$6.33	\$1.70	-73.1%

Notably, the average price of gas increased by over 100% between the years covered in the IA (\$3.24/MMBtu) and the first year of DA A/S (\$6.82/MMBtu). This resulted in a commensurate increase in the day-ahead Hub LMP, which rose from \$33.48/MWh to \$71.44/MWh. While there was little change in the average day-ahead load forecast between the two periods, the system experienced higher summer and winter peak loads during the first year of DA A/S.⁵³

Meanwhile, compared with ISO-NE’s original IA, the “IA Refresh” produced a higher average competitive offer (\$12.78/MWh compared with \$10.00/MWh), but the mix of components changes: expected closeout and AIC are higher, while the risk premium is lower. The increase in expected closeout was generally in-line with that observed for energy market prices, while the marked increase in the AIC largely stemmed from the extreme natural gas prices observed during Winter Storm Fern. The reduction in the (Sharpe-based) risk premium reflects changes in total profit

⁴⁹ The gas price is the Intercontinental Exchange next-day index price for Algonquin Non-G.

⁵⁰ This represents the maximum peak hourly load observed in June, July, or August. For the 2019-2021 period, this represents the average of the three summer maximums. This information comes from: https://www.iso-ne.com/static-assets/documents/2023/08/enepk_report.xlsx.

⁵¹ This represents the maximum peak hourly load observed in December, January, or February. For the 2019-2021 period, this represents the average of the three winter maximums. This information comes from: https://www.iso-ne.com/static-assets/documents/2023/08/enepk_report.xlsx.

⁵² The values shown for the competitive offer and its components (Expected Closeout, AIC, and Risk Premium) are simple (unweighted) averages across all resources and hours within each study period/day set. The averages are based on all submitted offers rather than the subset selected by the market-clearing engine to provide DA A/S.

⁵³ The peak load observed in summer 2025 was the highest recorded load in New England in over 10 years. See the IMM’s Summer 2025 Quarterly Markets Report for more information: <https://www.iso-ne.com/static-assets/documents/100029/2025-summer-quarterly-markets-report.pdf>.

variability (relative to the real-time-only alternative) from taking on a DA A/S award for participating resources.⁵⁴

The high-level results of a comparison between the IMM’s “IA Refresh” and the simulated “No DA A/S” scenario are provided in Table 5-4 below.

Table 5-4: Estimated Change in Market Costs from DA A/S (IMM “IA Refresh”)

Category	No DA A/S (\$M)	IMM Refresh (\$M)	Delta (\$M)	Delta (%)
DA Energy	\$10,437	\$11,029	\$592	5.7%
<i>LMP</i>	\$10,437	\$10,214	-\$222	-2.1%
<i>FER Price</i>	\$0	\$815	\$815	
DA A/S	\$0	\$146	\$146	
<i>Credits</i>	\$0	\$340	\$340	
<i>Closeouts</i>	\$0	-\$194	-\$194	
Total Charges/Credits	\$10,437	\$11,175	\$738	7.1%
Cost of Incremental RT Energy	\$140	\$136	-\$5	-3.3%
Total Cost/Revenue Change	\$10,577	\$11,311	\$733	6.9%

We estimate that the incremental cost of DA A/S using the similar assumptions to those used in the original IA would have resulted in an increase of \$733 million (6.9%) in total costs over the first year.⁵⁵ This is an indication that changes in system and market conditions explain a large share (75%) of the total estimated incremental costs of DA A/S during its first year. Notably, the “IA Refresh” shows that not only did the level of incremental costs (\$733 million) increase substantially relative to the original IA (\$140 million) but so did the ratio of these costs relative to total market cost (6.9% in the “IA Refresh” versus 3.1% in the original IA).

As was the case with the estimated incremental costs of DA A/S discussed in Section 4.2, we observe a similar phenomenon of high-cost days playing a large role on incremental costs in the “IA Refresh”. We estimate that 13 days, most of which were the same as those noted in Section 4.2, accounted for approximately 50% of incremental costs of DA A/S in the “IA Refresh.”⁵⁶ Absent

⁵⁴ This could happen if the composition of participating resources shifts over time toward units for which DA A/S participation adds less incremental variance, or more generally where real-time energy margins frequently offset closeout exposure.

⁵⁵ The “IA Refresh” uses actual values from the first year of DA A/S while maintaining the following assumptions of the original IA: (1) all generators make DA A/S offers at their Economic Maximum (EcoMax) and all DARDs at their Max Consumption; (2) all generators and DARDs make DA A/S offers priced at their Benchmark Level plus a risk premium determined by the Sharpe ratio (see Section 6.3 for more information); (3) Wind, solar, and demand response resources do not make DA A/S offers; (4) the Maximum Daily Award Limit (MDAL) for all resources was set such that they could not bind. The “IA Refresh” did not include any additional energy demand bids as were done in the original IA (noted in Footnote 4848). Additionally, all DA A/S offers were based on Benchmark Levels that incorporated participant-submitted values that were approved by the IMM as well as any interventions the IMM made to expected closeouts, reflecting the assumption that these adjusted values most accurately represented competitive offers.

⁵⁶ The days were: June 23-24, 2025; July 6-7, 2025; July 17, 2025; July 29-30, 2025; August 12-13, 2025, and January 25-28, 2026.

these 13 days, the incremental costs of DA A/S in the “IA Refresh” would have represented only 4.0% of total market costs, making it more in-line with the original IA (3.1% of total market costs). These results suggest that market performance during periods of system stress crucially impacted program costs in a way they did not during the years covered in the IA. In fact, there were eight days in the “IA Refresh” when the incremental DA A/S costs exceeded two percent of the total annual incremental DA A/S costs, while there was only one such day in three years when this occurred in the IA.

If changes in system and market conditions account for \$733 million of the total \$974 million that we estimate for the incremental costs of DA A/S, a natural follow-up question is: what explains the remaining \$241 million? The most important differences between the “IA Refresh” and observed first-year outcomes are likely to be (1) participation and (2) differences between observed DA A/S offer prices and estimated competitive offer prices (including risk premiums).

The IA assumed broader participation of eligible capacity than was actually observed during the first year of the new design. These quantity-side decisions reduce market liquidity, raise inter-product opportunity or “redispatch” costs, and can amplify tight-hour price effects. Market participation is looked at in more detail in Section 6.1.

Additionally, differences between observed DA A/S offer prices and cost-based benchmarks also likely contributed to higher prices. Additional coverage of DA A/S offer prices is provided throughout this document, including an analysis of marginal DA A/S offers (Section 5.3), a discussion of risk premia (Section 6.3), comparison of DA A/S offer prices relative to benchmark levels (Section 7) and an evaluation of expected closeout accuracy (Section 8.2).

5.2 Impact of New Market Constraints

DA A/S introduced several new constraints into the day-ahead market at the same time, which has made it challenging to determine the extent to which each constraint has driven observed outcomes. In this section, we analyze the relationship between specific constraints and costs to determine the key drivers of observed costs in the first year of the new market design.

5.2.1 Flexible Response Services

The FRS constraints are the set of constraints that were added in DA A/S to ensure that the ISO has enough fast-starting and fast-ramping capability to quickly respond to a large supply loss. One important insight related to the incremental cost of DA A/S that the IMM first made in its Summer 2025 Quarterly Markets Report (QMR) is that, while the costs primarily manifest themselves in the FER payment, they primarily originate from the FRS requirements.⁵⁷ To arrive at that conclusion, we used the Integrated Market Simulator to run the following scenario:

- 1) **FRS Only:** a scenario in which the FER constraint is ‘turned off’ but the FRS constraints remain ‘turned on.’ This scenario is intended to reflect a modified version of the current DAM that doesn’t have the FER constraint.

We re-ran this FRS Only scenario using a full year of market data and the results are compared against the No DA A/S case in the table below.

Table 5-5: Estimated Change in Market Costs with only the FRS Constraints

Category	No DA A/S (\$M)	FRS Only (\$M)	Delta (\$M)	Delta (%)
DA Energy	\$10,437	\$10,805	\$368	3.5%
<i>LMP</i>	\$10,437	\$10,805	\$368	3.5%
<i>FER Price</i>	\$0	\$0	\$0	
DA A/S	\$0	\$216	\$216	
<i>Credits</i>	\$0	\$397	\$397	
<i>Closeouts</i>	\$0	-\$181	-\$181	
Total Charges/Credits	\$10,437	\$11,020	\$84	5.6%
Cost of Incremental RT Energy	\$140	\$170	\$30	21.1%
Total Cost/Revenue Change	\$10,577	\$11,190	\$613	5.8%

We estimate that incremental DA A/S costs would have been \$613 million if only the FRS constraints had been incorporated into the market clearing process and there was no FER constraint. This equates to 65% of the estimated total incremental DA A/S costs (\$974 million). Notably, the incremental cost increases shift from FERP-based payments when the FER is included to LMP-based payments when the FER is removed. This finding highlights the distinction between a settlement channel (the FERP), and the main cost driver (the FRS requirements). Because energy,

⁵⁷For more information, see section 3.5.7 of our Summer 2025 QMR, available here: <https://www.iso-ne.com/static-assets/documents/100029/2025-summer-quarterly-markets-report.pdf>.

EIR, and FRS awards compete for the same scarce resource capability in the co-optimized market, FRS scarcity can raise the marginal cost of satisfying the FER. When the FER constraint is removed, the same underlying scarcity is reflected more directly in the day-ahead LMP.

Co-optimization of energy and reserves has several important cost implications. The first is that energy prices are likely to rise. This happens because some low-cost supply that would otherwise be dispatched to provide energy may instead be used to satisfy one of the reserve requirements, which may result in higher-cost supply at the margin and consequently a higher energy price. The second is that clearing prices now incorporate cross-product opportunity costs, which are the costs incurred by resources (in the form of foregone profits) when the market clearing engine schedules them to satisfy one requirement when it would have been more profitable to meet another.

We can get a sense of the order of magnitude of these cost implications in Table 5-5. For example, day-ahead LMP-based payments increased by **\$368 million** (3.5%) between the No DA A/S and the FRS Only scenarios. This increase in energy market costs should be generally indicative of the cost associated with the “redispatch” of energy to satisfy reserve requirements and any opportunity costs that show up in the LMP.⁵⁸

Another way to assess the scale of opportunity costs is to set all DA A/S offer prices for resources that historically offered into the market to \$0/MWh and then determine the cost of meeting day-ahead market constraints—energy balance, FER, and operating reserve requirements—based on offered capability.⁵⁹ Any non-zero DA A/S clearing prices that result from this approach are in theory a result only of cross-product opportunity costs, because DA A/S offer prices play no role (as they are set at \$0/MWh). Under this simulation, total E&AS costs amount to \$10,893 million, implying incremental costs of **\$316 million** (\$2.67/MWh). This approach is somewhat analogous to real-time reserve prices, which are based solely on opportunity cost (or administrative penalty factors).

5.2.2 Forecast Energy Requirement

The *incremental* impact of the FER constraint (*incremental* to a scenario that already includes the FRS constraints) must account for the remaining 35% (\$361 million) of the estimated total incremental DA A/S costs (\$974 million). It is likely that using the market simulator to assess the impact of the FER constraint alone would result in a substantially lower incremental cost estimate given the interaction of FER constraint and the FRS constraints disappears when only the FER constraint is modeled. In other words, the costs of constraints are not additive; the incremental cost of satisfying the FER increases as ancillary service capability becomes scarcer.

For the year, the FER constraint represents a larger share of the estimated incremental DA A/S costs than when we looked at it over the first six months in our Summer 2025 QMR (at that time it

⁵⁸ The term “redispatch” is a common shorthand for the co-optimized displacement of energy by reserve awards. Strictly speaking, however, the market clearing engine only produces a single co-optimized dispatch (i.e., there is no initial “dispatch” and then subsequent “redispatch”).

⁵⁹ An important caveat here is that setting EIR offer prices to \$0/MWh in this simulation has the effect of clearing more “cheap” EIR awards than relatively more expensive energy from physical supply.

accounted for ~19%). This is largely the result of two days: January 26 and January 27, 2026. We estimate that the incremental impact of the FER constraint on these two days added \$165 million to incremental DA A/S costs. In other words, absent these two days, the incremental impact of the FER constraint would have only been \$195 million (rather than \$361 million), representing about 28% (rather than 35%) of estimated total incremental DA A/S costs (\$702 million, which represents the incremental costs of DA A/S with January 26, 2026, and January 27, 2026, removed).

5.3 FRS Costs Examined

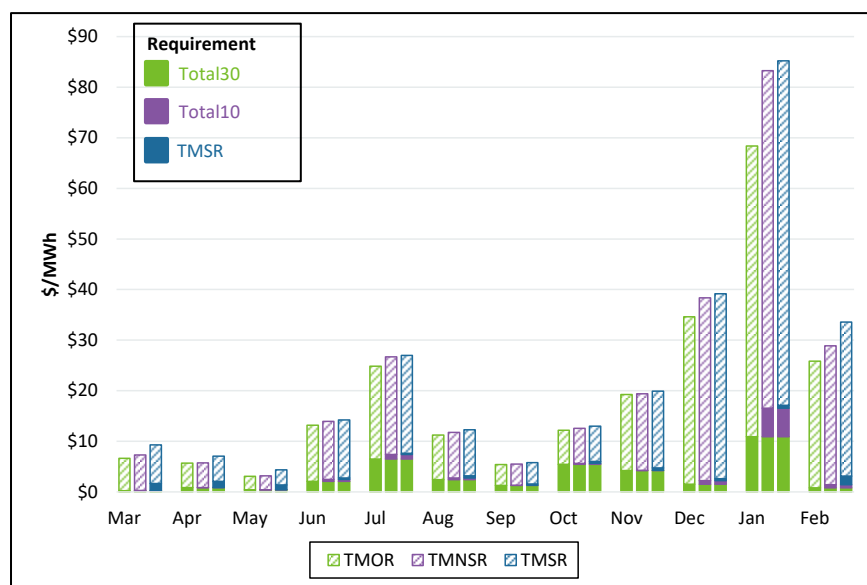
The following section explores how opportunity costs and the various cost components of a DA A/S offer may have impacted FRS clearing prices.

5.3.1 Opportunity Costs

To estimate the extent to which opportunity costs impacted FRS clearing prices, we assumed that highest offer price of a DA A/S product cleared to satisfy that requirement was the “marginal” offer. The difference between this offer price and the ancillary services clearing price is our estimate of the opportunity cost for a specific FRS requirement in that hour. This approach indicated that opportunity costs were \$77 million, which represents a low-end estimate of the opportunity costs given that the *true* marginal DA A/S offer may have a lower offer price.

The impact of opportunity costs associated with each FRS requirement impacted average hourly FRS product clearing prices is depicted by month in Figure 5-1 below. The portion of each column reflects the opportunity cost associated with a specific FRS constraint (e.g., the shaded green series reflects opportunity cost of satisfying the Total 30 requirement) while the total height of the column is the average monthly clearing price for the specific FRS product.⁶⁰

Figure 5-1: Impact of Opportunity Costs on FRS Clearing Prices



Opportunity costs made up a small but, at times, meaningful portion of FRS clearing prices during the first year of DA A/S. The most impactful requirement on FRS clearing prices was the Total 30 requirement, which binds in every hour under this design, although its impact did vary considerably by month. Interestingly, the months with high Total 30-related opportunity costs coincide with

⁶⁰ As mentioned in Section 3.1.2, the clearing price of the FRS products tend to be closely aligned given their price formation mechanics. Specifically, FRS clearing prices “cascade up,” which produces the following relationship between the product clearing prices: $CP_{TMSR} \geq CP_{TMNSR} \geq CP_{TMOR}$.

periods of system stress (July and January) or high levels of generator outages (October and November). Of additional relevance is the finding that four of the five days with the highest average hourly Total 30-related opportunity costs occurred during the four-day period from January 26-29, 2026. Section 5.3.3 examines the drivers of outcomes on the highest DA A/S cost days, including those observed in January.

Opportunity costs associated with the Total 10 requirement, which bound in 33% of hours over the first year, impacted TMNSR and TMSR clearing prices to various degrees over the course of the year. These costs can be seen most visibly in January 2026. Similar to the observation above, the four-day period from January 26-29, 2026, had four of the five days with the highest Total 10-related opportunity costs.

Lastly, the opportunity cost associated with the TMSR requirement, which bound in only 20% of hours in the first year, generally did not have a significant impact on TMSR clearing prices. TMSR-based opportunity costs played no role in clearing prices on 11 of the top 12 high-cost days.⁶¹

5.3.2 Offer Costs

This section explores how the various cost components of a DA A/S offer may have impacted FRS clearing prices. Specifically, this section examines the relationship between the expected closeout, the Avoidable Input Cost (AIC), and the offer price of the “marginal” offer for the Total 30 requirement.^{62,63}

It is important to note that it is not possible to separate the offer price of the “marginal” offer into its distinct components (i.e., expected closeout, the AIC, and risk) given that participants do not submit offer prices at this granularity. For this reason, in Figure 5-2 below, we simply overlay the monthly average “marginal” offer price for the Total 30 requirement (shown as green columns) with two line series: (1) a red line that shows the monthly average expected closeout and (2) a black line that shows an estimate of the AIC component of the “marginal” offer, also averaged by month.⁶⁴

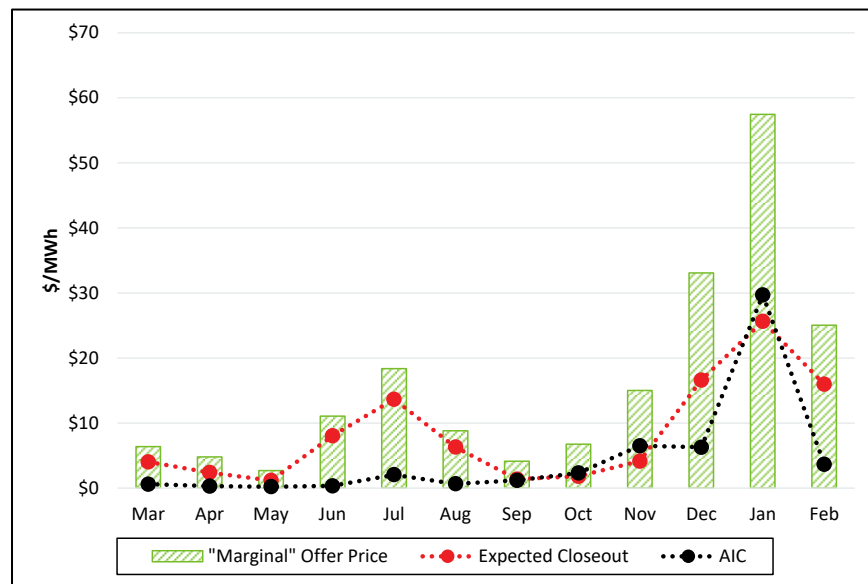
⁶¹ The 12 high-cost days are defined in Section 4.2.

⁶² As discussed in Section 5.3.1, we use the offer with the highest offer price for any DA A/S product cleared to satisfy that requirement as the proxy for the “marginal” offer.

⁶³ We only look at the Total 30 requirement here because it is the most impactful FRS requirement in regard to FRS product price formation as well as the most straight-forward to assess.

⁶⁴ Our estimate of the AIC assumes that the AIC was fully reflected in a resource’s offer price. As such, it can be viewed as an upper limit on the extent to which this offer component may have appeared in FRS offer prices.

Figure 5-2: “Marginal” Offer Price for Total 30 Requirement with Offer Components



The offer price of the “marginal” offer for the Total 30 requirement shows a strong positive relationship with the expected closeout value, rising during periods when the expected closeout was higher (e.g., July, December, January, and February) and falling during other periods when the expected closeout was lower. Meanwhile, the AIC component displays a clear seasonality, appearing to have very little relevance outside of the winter. This likely stems from how the AIC is determined for gas resources, where the AIC is intended to reflect the portion of the gas purchase cost that is not expected to be covered by energy production in the real-time market.⁶⁵

During the winter, high gas prices can create large AIC components particularly in conditions where lower-price resources are expected to set the price of energy in the real-time market. Using this approach for estimating the AIC, we find that the five days where the AIC may have had the largest impact on the shadow price of the Total 30 requirement (and therefore on the clearing prices of all the FRS products) were the five days from January 25-29, 2026.

5.3.3 Key Drivers and Outcomes for the 12 Highest-Cost DA A/S Days

When examining the relationship between fixed and priced demand—defined here as demand expected to be met through real-time energy—and the load forecast in the day-ahead market, we find no evidence of systematic underclearing. On average, the sum of cleared fixed and priced load exceeded the load forecast by approximately 1.4% both during the first year of DA A/S and in the year prior (March 1, 2024, to February 28, 2025). However, on the 12 highest-cost DA A/S days, the

⁶⁵The AIC for a gas resource = $\max\{0, (\text{Gas Price} \times \text{Resource Average Heat Rate}) - \text{Expected Realtime LMP}\}$. For more information, see Section III.A.8.2.2.(a) of the ISO-NE Tariff: https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_append_a.pdf.

level of offered and cleared demand relative to the load forecast appears to play a more prominent role in FER outcomes.

In Table 5-6 (Summer) and Table 5-7 (Winter), we examine the drivers of the FER price outcomes observed across these 12 days, including the role of load clearing relative to the DA load forecast and broader system conditions.

Table 5-6: Summer Highest-Cost DA A/S Days

	23-Jun	24-Jun	25-Jun	7-Jul-25	17-Jul	25-Jul	13-Aug
Forecasted Load	23,800	25,310	23,960	22,800	24,200	23,000	24,100
Temp (min)	69	74	74	72	74	72	67
Temp (max)	90	97	89	86	88	89	88
Natural Gas Price	\$4.37	\$5.75	\$5.01	\$3.26	\$11.30	\$4.92	\$4.27
DA LMP	\$111.14	\$156.73	\$83.79	\$103.56	\$125.64	\$115.31	\$84.95
TMSR Price	\$81.30	\$113.66	\$62.62	\$62.60	\$69.15	\$65.02	\$70.68
TMNSR Price	\$81.30	\$113.66	\$62.62	\$62.60	\$69.15	\$65.02	\$70.68
TMOR Price	\$73.52	\$107.99	\$57.81	\$56.13	\$51.33	\$62.28	\$62.03
FER Price	\$0.20	\$3.24	\$24.75	\$0.00	\$15.99	\$0.27	\$23.49
Net Interchange	1,898	2,236	2,442	2,468	3,706	2,081	2,643
Outages	1,504	2,131	1,827	2,017	1,504	1,442	1,169
DA A/S Offered MWs	8,755	8,848	8,949	6,910	8,780	9,043	9,100
Cleared load as % of RT Load Obligation	95%	93%	94%	100%	96%	102%	101%
Cleared load as % of DA Load Forecast	101%	99%	95%	101%	97%	105%	99%

Table 5-7: Winter Highest-Cost DA A/S Days

	25-Jan	26-Jan	27-Jan	28-Jan	29-Jan
Forecasted Load	19,500	19,650	19,700	19,600	19,550
Temp (min)	4	14	5	2	3
Temp (max)	19	22	19	21	21
Natural Gas Price	\$45.22	\$45.22	\$89.84	\$99.32	\$60.99
DA LMP	\$433.96	\$436.01	\$639.14	\$423.31	\$346.81
TMSR Price	\$219.08	\$365.43	\$750.60	\$327.92	\$141.32
TMNSR Price	\$219.08	\$365.43	\$750.60	\$327.92	\$131.27
TMOR Price	\$214.49	\$328.24	\$423.16	\$313.78	\$105.73
FER Price	\$60.82	\$231.18	\$349.80	\$32.88	\$15.74
Net Interchange	106	1,076	1,900	2,936	2,400
Outages	3,934	4,553	4,295	4,416	4,286
DA A/S Offered MWs	9,788	8,662	8,599	9,227	9,315
Cleared load as % of RT Load Obligation	93%	98%	97%	99%	99%
Cleared load as % of DA Load Forecast	96%	94%	94%	97%	97%

For these 12 days, load clearing outcomes exhibit clear seasonal differences when compared to the day-ahead load forecast. During the summer high-load periods, cleared load generally remains close to the forecast and at times exceeds it, indicating a mix of under- and overclearing. By contrast, the tight winter days are characterized by consistent underclearing, with cleared load falling below the DA forecast on all observed days.

These differences in clearing behavior are reflected in FER pricing outcomes. For the summer tight days, FER prices are relatively low and tend to increase when the system underclears relative to the forecast, while remaining near zero on days when the system overclears. For the winter tight days, FER prices are significantly higher; however, their magnitude does not vary in a clear way with how much the system underclears. Similar levels of underclearing on some tight winter days correspond to a wide range of FER outcomes, indicating that underclearing alone does not explain the size of FER prices for these days.

Other system conditions distinguish the winter period from summer. Winter days are associated with higher outage levels and, at the onset of the higher FER period, reduced net interchange. These conditions coincide with the period in which FER outcomes are elevated, suggesting tighter overall system conditions. Natural gas prices are also notably higher in winter, aligning with the broader increase in FER prices, although differences in gas prices across individual winter days do not closely track the variation in FER outcomes.

It is difficult to attribute the high FER prices alone to any one factor, and indeed evidence to date indicates that supply-side (e.g., outages and interchange over the fall season) as well as demand-side factors impact the FERP. However, during the high-stressed winter period the data indicates that LSE under-clearing (compared to the load forecast) likely had significant impact on the high FER pricing outcomes.

Section 6

Assessment of Market Competitiveness

This section evaluates whether DA A/S market outcomes are consistent with competitive behavior. In so doing, this section serves as the IMM’s competitiveness assessment that is required under Section III.A.17.2.5 of the ISO-NE Tariff.

An accurate assessment of the level of competition is crucial because it helps indicate the extent to which the costs incurred by load for these services reflect competitive market outcomes rather than the exercise of market power. A fundamental feature of competitive markets is the presence of both multiple buyers and multiple sellers, which limits the ability of any individual participant to influence price. While this describes the day-ahead energy market,⁶⁶ the DA A/S market deviates from this idealized version in a very notable way: the market has only one buyer, the ISO, who is purchasing these services on behalf of load.

Accordingly, the objective of this assessment is not to test whether the DA A/S market satisfies the conditions of perfect competition. Rather, the goal is to evaluate whether the observed market outcomes are consistent with the outcomes one would observe in a competitive market. Given the characteristics of the market, this assessment requires a close examination of the supply side of the DA A/S market.

Consequently, the subsequent analysis focuses on the supply side of the market. The first section examines the overall level of market participation. The second section explores the structure of the supply, looking specifically at the level of market concentration and estimating the extent to which the exercise of market power is possible. The third section evaluates how observed DA A/S outcomes compare against outcomes produced using IMM-estimated competitive offers.

Key Takeaways

DA A/S market outcomes indicate that costs were broadly consistent with competitive market conditions during the period.

Offered FRS capability consistently exceeded requirements and increased over the first year of DA A/S, though available supply is more constrained after accounting for market clearing effects—particularly for TMSR, which exhibits relatively tight margins, while Total 10 and Total 30 maintain larger margins. EIR plays a limited role, with generally low cleared volumes that increase during tighter system conditions. Despite rising participation, some capability remains unoffered due to commercial, operational, and risk considerations. Overall, participation has not raised concerns about physical withholding, though it remains an important driver of outcomes particularly during stressed system conditions.

⁶⁶ The IMM found that day-ahead energy market exhibited competitive outcomes in 2025. For more information, see its 2025 Annual Markets Report, available here: <https://www.iso-ne.com/static-assets/documents/100035/2025-annual-markets-report.pdf>.

DA A/S markets exhibit moderate levels of structural concentration, which increase when capability is measured on an ex-post basis due to market clearing effects (e.g., when demand for energy is considered). Concentration is highest for TMSR, reflecting the more limited set of resources capable of providing fast-response reserves, while Total 10 and Total 30 markets are less concentrated.

Despite this structural concentration, DA A/S offer behavior appears broadly consistent with competitive, risk-adjusted benchmarks. Simulations using both Sharpe-based and CVaR-based risk premia produce cost outcomes that are close to, or modestly above, those observed with participant offers. The Sharpe-based framework yields results very similar to observed outcomes, suggesting that participants are embedding risk premiums consistent with managing overall profit variability. The CVaR framework, which places greater weight on tail-risk exposure, results in somewhat higher costs, particularly under stressed conditions. On balance, observed outcomes indicate that participant offers incorporate reasonable, but not excessive, compensation for risk.

6.1 Market Participation

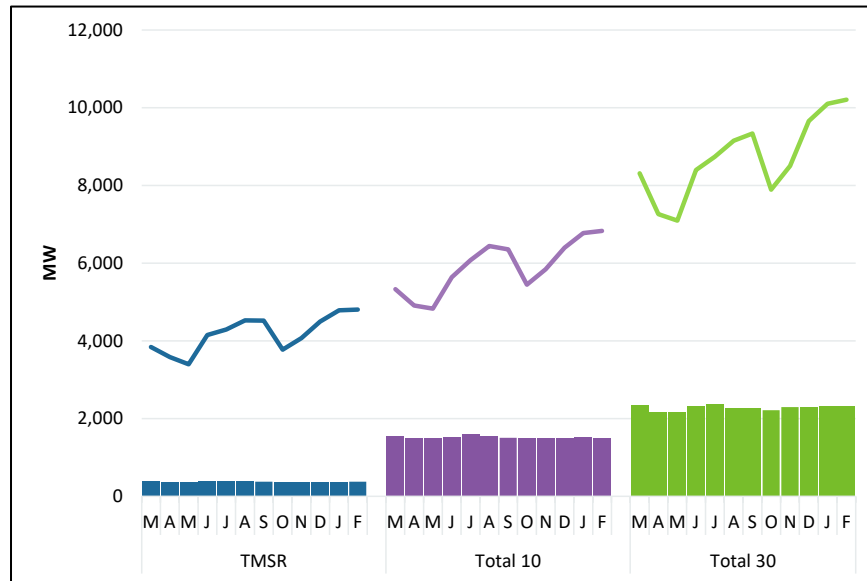
The first section examines the level of participation in the FRS markets over the first year of DA A/S, the second section examines EIR participation, and the last section discusses observations related to unoffered capability.

6.1.1 Flexible Response Services

The offered FRS capability was typically several times larger than the corresponding requirement, and this offered capability generally increased over the first year of the program. This can be seen in Figure 6-1, which shows the average hourly FRS requirements (as bars) and offered capability (as lines) by month.⁶⁷

⁶⁷ Offered capabilities reflect participant-submitted DA A/S offer quantities limited by physical resource characteristics (e.g., ramp rate, EcoMax). Importantly, this figure does not account for the use of Maximum Daily Award Limit (MDAL) parameter by resources as a way to manage the amount DA A/S awards they can clear over the 24-hour day-ahead market clearing. We have seen this parameter commonly used by resources such as limited energy generators (e.g., oil, pondage hydro, pumped storage, and battery storage), which marks an important difference relative to the assumptions used in the Impact Assessment discussed in Section 5.1.

Figure 6-1: Offered FRS Capability relative to Requirements, Ex-ante



Between March 2025 and February 2026, offered TMSR capability rose by roughly 1,000 MW (from 3,800 MW to 4,800 MW), offered Total 10 capability rose by roughly 1,500 MW (from 5,300 MW to 6,300 MW), and offered Total 30 capability rose by roughly 1,900 MW (from 8,300 MW to 10,200 MW). However, the offered capability displayed a seasonality, with participation declining in the spring and fall (when resources tend to undertake planned outages) and then rising in the summer and winter. Meanwhile, the average FRS requirements did not change much by month. The average TMSR requirement was 380 MW, the average Total 10 requirement was 1,521 MW, and the average Total 30 reserve requirement was 2,278 MW.

Several elements of the co-optimized day-ahead market clearing process can limit the DA A/S capability that can be used to satisfy the FRS requirements. Overlooking these limits may lead to an incomplete understanding of the DA A/S market structure. For example, some offered DA A/S capability may be: (1) more valuable to the system when cleared as energy, (2) accessible only from an online state (and the resource may not receive a day-ahead commitment), or (3) limited due to binding transmission constraints.

Consequently, throughout this assessment we use two definitions of supply: *ex-ante* capability (i.e., offered capability) and *ex-post* capability (i.e., offered capability that has been adjusted to account for the factors noted above).⁶⁸

- *Ex-ante* capability is calculated from the resource’s offered DA A/S quantity and physical parameters before market clearing. For online capability, the measure reflects the lesser of (1) headroom between EcoMax and EcoMin and the (2) relevant ramp capability over the

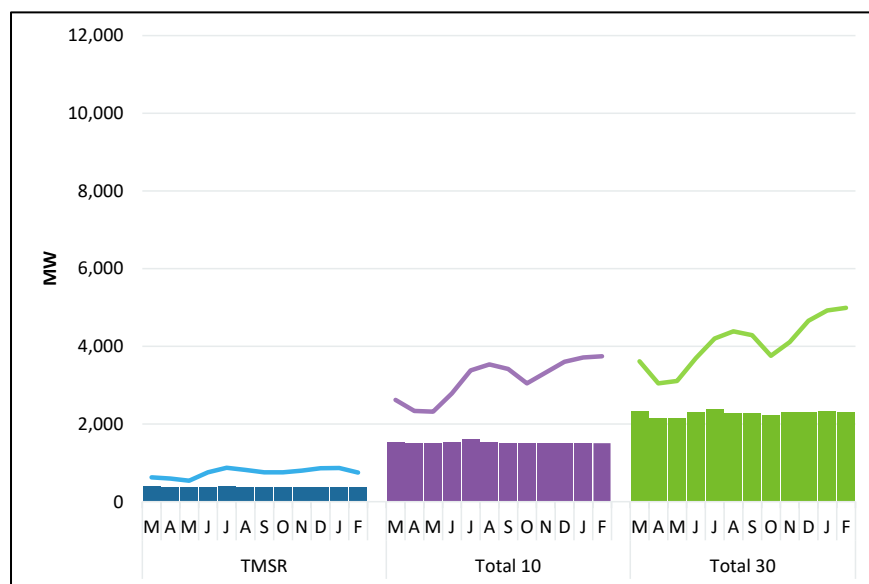
⁶⁸ Specifically, we adjust the offered DA A/S capability downward by the amount of capability that (1) cleared for energy, (2) was offered by non-fast start resources that did not receive a DA commitment, and (3) was behind a binding transmission constraint.

response period. For offline fast-start capability, it reflects the lesser of EcoMax and the applicable Claim10 or Claim30 value.

- *Ex-post* capability starts from the same offered capability but reduces it for capacity that clears for energy, capacity that is not available because the resource was not committed, and capacity limited by binding transmission constraints.⁶⁹

Ex-ante measures can overstate supply because they ignore these clearing effects, while ex-post measures can understate supply because they evaluate capability after the day-ahead market has produced an efficient day-ahead schedule. However, when viewed together, these measures can provide a more complete supply picture. The ex-post perspective of offered FRS capability is illustrated in Figure 6-2 below. Similar to the chart above, this figure shows the average hourly offered FRS capability (as lines) and FRS requirements (as bars) by month.⁷⁰

Figure 6-2: Offered FRS Capability relative to Requirements, Ex-post



As can be seen above, FRS capability becomes more constrained when viewed from a post market clearing perspective. Ex-post TMSR capability tracked tightly with the TMSR requirement over the first year of DA A/S, with an average margin of about ~370 MW per hour. This makes intuitive sense when we consider TMSR procurement in the context of the cost-minimization objective of the day-ahead market. Given that spinning reserve is mostly provided by resources that must be committed

⁶⁹ This ex-post supply assessment is further utilized in the market structure assessment in section 6.2 below.

⁷⁰ Offered capabilities reflect participant-submitted DA A/S offer quantities limited by physical resource characteristics (e.g., ramp rate, EcoMax). Importantly, this figure does not account for the use of Maximum Daily Award Limit (MDAL) parameter by resources as a way to manage the amount DA A/S awards they can clear over the 24-hour day-ahead market clearing. We have seen this parameter commonly used by resources such as limited energy generators (e.g., oil, pondage hydro, pumped storage, and battery storage), which marks an important difference relative to the assumptions used in the Impact Assessment discussed in Section 5.1.

at a cost to provide energy (i.e., have non-zero startup commitment costs), one would not expect an excess of this capability when the market is viewed from a post-clearing perspective.

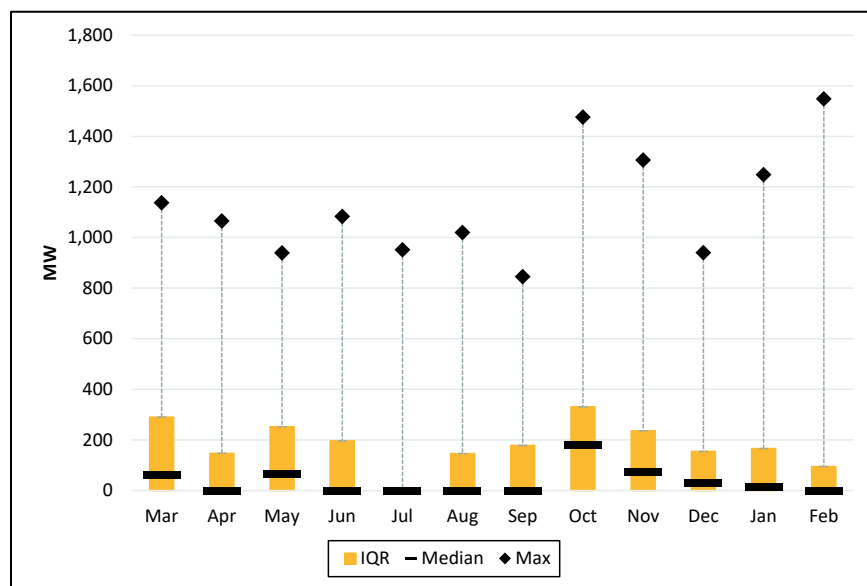
In contrast, ex-post Total 10 and Total 30 capabilities generally had larger margins relative to their respective requirements and these margins are more reflective of the seasonal effects described earlier. Additionally, these ex-post capabilities display clearer upward movement over time as additional resource capability entered the market. The ex-post Total 10 and Total 30 margins tend to be larger than the TMSR margin given that these requirements can be met by both online and *offline* resources.

6.1.2 Energy Imbalance Reserves

There is no strict requirement on the level of EIR that must clear per hour. Instead, the market clearing engine will determine the level of cleared EIR in tandem with its determination of the level of cleared day-ahead energy awards on physical resources, ensuring that, collectively, the two values satisfy the FER. Meanwhile, the supply side of the market is the largest for all the DA A/S products as EIR capability reflects the increase in energy output that resources can achieve in 60 minutes.⁷¹

In general, only small amounts of EIR are cleared to satisfy the FER, but clearing does vary by hour. This can be seen in Figure 6-3, which shows the hourly distributions of cleared EIR MW by month over the first year of DA A/S, highlighting the interquartile range (IQR), median, and maximum values.

Figure 6-3: Cleared EIR MW



⁷¹ Given that there is no strict requirement for EIR and that the supply pool is the largest of all the DA A/S products, the FRS products receive the majority of the focus in our assessment of DA A/S market competitiveness.

Across the year, median cleared EIR volumes were relatively low (generally under ~100 MW) and, in many months, the median value was 0 MW. However, there was a modest uptick in the fall when generators took winter readiness outages and the level of imports generally decreased. Maximum values (black markers) exhibit greater volatility, with pronounced spikes in October, November, January, and February.

6.1.3 Unoffered Capability

It is important to note that some capability chooses not to participate in the voluntary DA A/S market.⁷² In fact, while offered capability has far exceeded the FRS requirements, and participation has trended upwards, participation rates have peaked around an estimated 70% for 60-minute (i.e., EIR) capability, although participation has varied by resource type and fuel. Participants that choose not to participate, or to participate at reduced levels, in the DA A/S market have generally provided three reasons: commercial strategy, physical/operational constraints, and risk considerations. Each of these is discussed briefly below.

- Some participants indicated commercial strategy considerations influenced their decision not to participate in the DA A/S market. A few of these participants cited a focus on alternative, non-market-based revenue streams, most notably those attainable through Massachusetts Clean Peak Energy program. Power Purchase Agreements (PPAs) are likely influencing DA A/S offer behavior as well by prioritizing energy market participation.
- Physical and operational constraints also impacted certain resources decisions to limit their participation in the DA A/S market. Some participants described limitations related to fuel management, making reserve provision impractical. Other participants, particularly those with hydroelectric resources, cited that generation decisions can affect downstream operations and water management schedules.
- Finally, some participants indicated that risk considerations played a role. These participants generally cited the view that a DA A/S award can expose certain resources to additional financial risk because these resources cannot rely on inframarginal real-time energy market revenues to offset potential losses.⁷³ This reasoning applied both to broad classes of resources as well as certain energy segments, such as upper block or duct firing ranges, which tend to have significantly higher marginal costs.

The IMM has consulted with participants regarding their participation levels in the DA A/S market, particularly around periods of stressed system conditions such the five-day period from January 25, 2026, to January 29, 2026, that coincided with Winter Storm Fern. Participation levels have generally not raised physical withholding concerns that would impact overall competitive cost

⁷² There is no must-offer rule in the DA A/S market. For discussion on this topic, please see pages 111-113 of the testimony of Dr. Matthew White in support of DA A/S contained within the ISO's filing to FERC, which is available here: https://www.iso-ne.com/static-assets/documents/100004/rev_to_est_jointly_optimized_day-ahead_mkt_for_energy_and_ancillary_services.pdf.

⁷³ For a discussion of this risk, see Section 6.3.

estimates. We will continue to monitor participation levels on an ongoing basis and require legitimate justification when lack of participation exceeds the Tariff-defined thresholds.⁷⁴

6.2 Market Structure

Market structure refers to the organization of a market, including the number and relative size of participating firms offering their ancillary services capability into the day-ahead market. Given that the capabilities needed to satisfy the various requirements are different, the natural lanes for this analysis are the requirements: ten-minute spinning reserve (TMSR), total 10-minute reserve (Total 10), and total 30-minute reserve (Total 30).⁷⁵

As mentioned in Section 3.1, the day-ahead market formulation includes nested FRS demand quantities (TMSR, Total 10, and Total 30). TMSR awards can satisfy each of the three FRS requirements; TMSR can satisfy the Total 10 and Total 30 requirements; and TMOR awards can satisfy only the Total 30 requirement. In the text, we refer to TMSR, Total 10, and Total 30 as shorthand for these nested requirements.

As discussed earlier, ex-ante measures can overstate supply and therefore underestimate market power because they ignore the co-optimization effects, while ex-post measures can understate supply and overstate market power because the day-ahead market can re-optimize commitment and reserve awards in response to offers.

Concentration Ratios

A concentration ratio measures the percentage of total capability accounted for by a set of the largest participants. Lower concentration ratios are indicative of more structurally competitive markets, while higher concentration ratios are indicative of less structurally competitive markets that are more susceptible to exercise or market power. In this analysis, CR4 refers to the share of total capability accounted for by the four largest participants, and CR8 refers to the share accounted for by the eight largest participants.

The DA A/S markets exhibit moderate levels of concentration, and these concentration levels increase across all markets when capability is measured on an ex-post basis. This can be seen below in Table 6-1, which shows the average CR4 and CR8 over the study period.

⁷⁴ See Section III.A.4 of the ISO-NE Tariff for more information on physical withholding.

⁷⁵ This assessment does not consider Energy Imbalance Reserve (EIR), which has no explicit requirement and has the largest supply of the DA A/S products given its 60-minute definition.

Table 6-1: DA A/S Market Concentration Ratios

Requirement	CR4		CR8	
	Ex-ante	Ex-post	Ex-ante	Ex-post
TMSR	61%	75%	79%	94%
Total 10	56%	60%	75%	82%
Total 30	50%	54%	72%	79%

On an ex-ante basis, the top four participants accounted for over 50% of the offered supply for all DA A/S requirements. Intuitively, the levels of concentration decreased as the response period increased (i.e., the concentration ratios for 30-minute capability are lower than those for 10-minute capability). Concentration levels increased across all requirements when capability is measured on an ex-post basis, reflecting the effects of joint optimization in day-ahead energy and ancillary services market. This pattern is most pronounced in the TMSR requirement, where CR4 rose from 61% percent under ex-ante capability to 75% under ex-post capability. When considering the eight largest participants, the concentration ratios for all three markets ranged between 72%-79% on an ex-ante basis and between 79%-94% on an ex-post basis.

It is important to recognize that the structure of supply for the DA A/S requirements differs from that in the energy market because only a subset of resources possesses the fast-start (i.e., Claim10 or Claim30) or fast-ramp capability needed to provide the requisite ancillary service. As a result, the supply of reserve capability is inherently more limited than the supply of energy, increasing the potential for concentration.^{76, 77}

Herfindahl-Hirschman Index

The Herfindahl-Hirschman Index (HHI) is a measure of market concentration that gives more weight to larger participants and considers the market shares of all participants.⁷⁸ Similar to concentration ratios, lower values are indicative of more competitive markets and higher values are indicative of less competitive markets.⁷⁹

⁷⁶ The IMM estimates that the real-time energy market had an annual average C4 during the on-peak hours that ranged between 40%-45% over the five-year period between 2020-2024. For more information, see Section 2.1.1 in our 2024 Annual Markets Report (AMR) (<https://www.iso-ne.com/static-assets/documents/100023/2024-annual-markets-report.pdf>). Please note that the C4 for energy reported in the 2024 AMR is based on *cleared* energy awards and the concentration ratios for DA A/S presented in this assessment are based on *offered* MWs.

⁷⁷ This comparison is intended only as a directional reference. Energy-market concentration measures are often based on cleared energy MW, while DA A/S concentration measures are based on offered or available reserve capability. The two measures therefore answer different questions, but the comparison is useful for illustrating that reserve-capability supply is inherently narrower than the broader energy supply base.

⁷⁸ The HHI is calculated as follows: $HHI = \sum_{i=1}^n (C_i)^2$; where C_i is the market share of the i -th largest participant (e.g., 25%) and n is the number of all participants that offer their capability.

⁷⁹ The highest possible HHI value is 10,000, which would occur when one firm accounted for 100% of the market.

The HHI values were consistent with the CR4 and CR8 values, indicating a range of concentration from low to moderate.⁸⁰ This can be seen below in Table 6-2, which shows the average HHI values over the study period.

Table 6-2: DA A/S Market Herfindahl-Hirschman Indices

Requirement	HHI	
	Ex-ante	Ex-post
TMSR	1,560	2,203
Total 10	1,320	1,368
Total 30	943	1,111

The HHI values reveal much of the same insight as the concentration ratios above. According to the Antitrust Division of the U.S. Department of Justice, the ex-ante TMSR and Total 10 markets are moderately concentrated while Total 30 is unconcentrated. Of specific note is the HHI for TMSR, which increased from an ex-ante value of 1,560 (moderately concentrated) to an ex-post value of 2,203 (highly concentrated). Ex-post Total 10 and Total 30 are both moderately concentrated according to those standards.

The concentration ratio and HHI measures provide useful summaries of structural concentration by describing how offered (or ex-post) capability is distributed across suppliers. However, these measures do not, by themselves, indicate whether concentration is competitively consequential in each hour, i.e., whether the DA A/S requirement could be met using capability outside a particular supplier or small set of suppliers, especially after accounting for the capability that is available. To evaluate when concentration can translate into potential market power, we therefore apply more insightful and dynamic metrics, the pivotal-supplier tests (PST) and the residual supply index (RSI), which explicitly compare residual (non-supplier) capability to the requirement on an hour-by-hour basis and identify periods when one or more suppliers are necessary to satisfy the requirements.

Pivotal Suppliers and Residual Supply Index

A pivotal supplier is a participant without whose offered capability a requirement could not be met. Periods when a market has a pivotal supplier are noteworthy because they can provide a useful screen identifying that a participant may have the ability to increase clearing prices. A related concept is the residual supply index (RSI), which is the proportion of a requirement that can be satisfied without the capability of the largest supplier.

⁸⁰ The Antitrust Division of the U.S. Department of Justice generally considers markets with HHI values below 1,000 as unconcentrated markets, HHI values between 1,000 and 1,800 as moderately concentrated market and HHI values >1,800 as highly concentrated markets. <https://www.justice.gov/atr/herfindahl-hirschman-index>

Statistics related to pivotal suppliers and the RSI are presented by requirement in Table 6-3 below.

Table 6-3: DA A/S Market Pivotal Supplier and RSI Statistics

Requirement	% of Hours with at least one Pivotal Supplier		RSI ⁸¹	
	Ex-ante	Ex-post	Ex-ante	Ex-post
TMSR	0%	38%	729	124
Total 10	0%	1%	271	147
Total 30	0%	3%	303	136

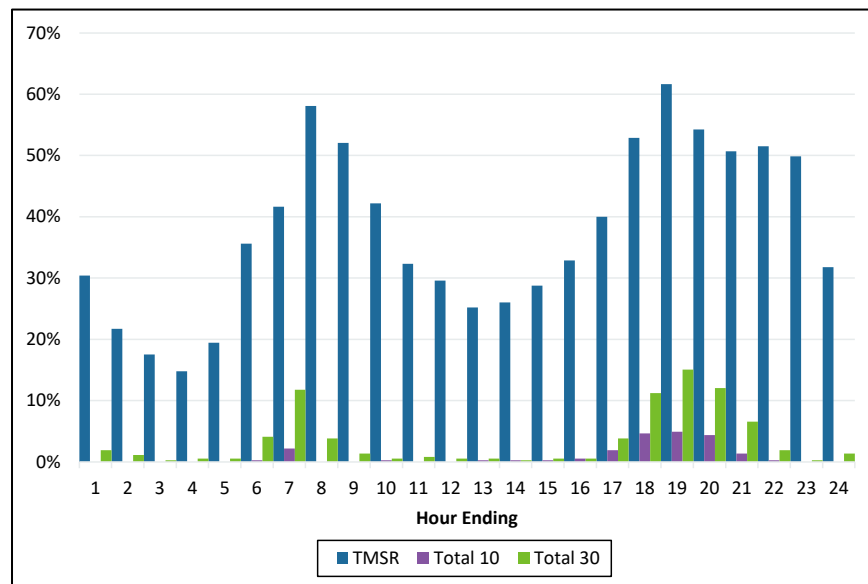
There were no hours with a pivotal supplier for any reserve market when capability is defined on ex-ante basis. By contrast, when ex-post capability is considered, at least one pivotal supplier is present in 38% of the hours in the TMSR market, while pivotal supplier occurrences remain infrequent in the 10- and 30-minute markets.

Consistent with the pivotal supplier results, average RSI values under the ex-ante capability definition suggest a generally robust supply picture with the values across all markets coming in well above 100. However, when capability is measured on an ex-post basis, RSI values decline across all markets. The decline is most significant for the TMSR requirement, which fell from over 700 to 124.

On an ex-post basis, the share of hours with at least one pivotal supplier varies significantly, rising during the morning and evening peak periods when reserve capability is converted to energy to satisfy higher loads. This can be seen in Figure 6-4 below, which shows the percentage of hours with at least one pivotal supplier by hour and market.

⁸¹ The residual supply index (RSI) represents the amount of demand and reserves that the system could satisfy without the largest supplier's available energy and reserves. If the value is less than 100, the largest supplier would be needed to meet demand and could exercise market power if permitted. Further, if the RSI is less than 100, there is one or more pivotal suppliers.

Figure 6-4: Percentage of Hours with at least One Pivotal Supplier (Ex-post) in the DA A/S Market



The percentage of hours with at least one pivotal supplier for the TMSR market rises from as low as 15% in hour ending (HE) 4 to 58% in HE 8 and 62% in HE 19. The pattern is similar, although more muted, for the Total 10 and Total 30 requirements; the share for Total 10 peaks at 5% in HE 19 while the share for Total 30 peaks at 15% during the same hour.

It is important to consider the TMSR market results in the context of the cost-minimization objective of the day-ahead market. Given that spinning reserve is mostly provided by resources that must be committed at a cost to provide energy (i.e., have non-zero startup commitment costs), one would not expect an excess of this capability when the market is viewed from an ex-post perspective. This effect is likely to raise the appearance of pivotality, especially to the extent that the resources that commonly clear TMSR awards have the same owner. Meanwhile, the Total 10 and Total 30 requirements can be met by both online and offline resources, which do not incur commitment costs, and therefore their ex-post market structure metrics tend to appear lower.

Further, the results above should also be considered in the context of FRS price formation. As noted in Section 5.2.1, in the majority of hours the TMSR clearing price is determined by the marginal offer for the Total 30-minute reserve constraint, which binds in every hour and whose price cascades up to influence the TMSR clearing price.⁸² This means that TMSR is generally competing with all 30-minute capability to set price.⁸³ Put differently, TMSR structural tightness

⁸² The ten-minute spinning reserve constraint bound in only 20% of hours during the first year of DA A/S.

⁸³ Additionally, the relatively low Reserve Constraint Penalty Factor (RCPF) for the TMSR (\$50/MWh) provides a form of safeguard against the exercise of market power in this market (when only the TMSR requirement is binding). This does not mean TMSR clearing prices are capped at \$50/MWh. Because FRS requirements are nested, TMSR awards can also satisfy Total 10 and Total 30 requirements, and the TMSR price can include the shadow prices of those broader constraints. The RCPF is therefore a useful safeguard against TMSR-specific market power, but it does not eliminate the need to monitor broader reserve scarcity and ex-post pivotal conditions.

does not necessarily imply that TMSR clearing prices are not determined by competitive market forces.

6.3 Offer Behavior

To assess whether market outcomes are consistent with competitive offer behavior, we conduct two simulations in which DA A/S offers are set at IMM benchmark levels, differing only in how the risk premium is defined. Together, these risk methodologies provide a range of competitive outcomes: one based on a return-per-unit-of-risk metric (Sharpe) and one based on a more conservative tail-risk measure (conditional Value at Risk).

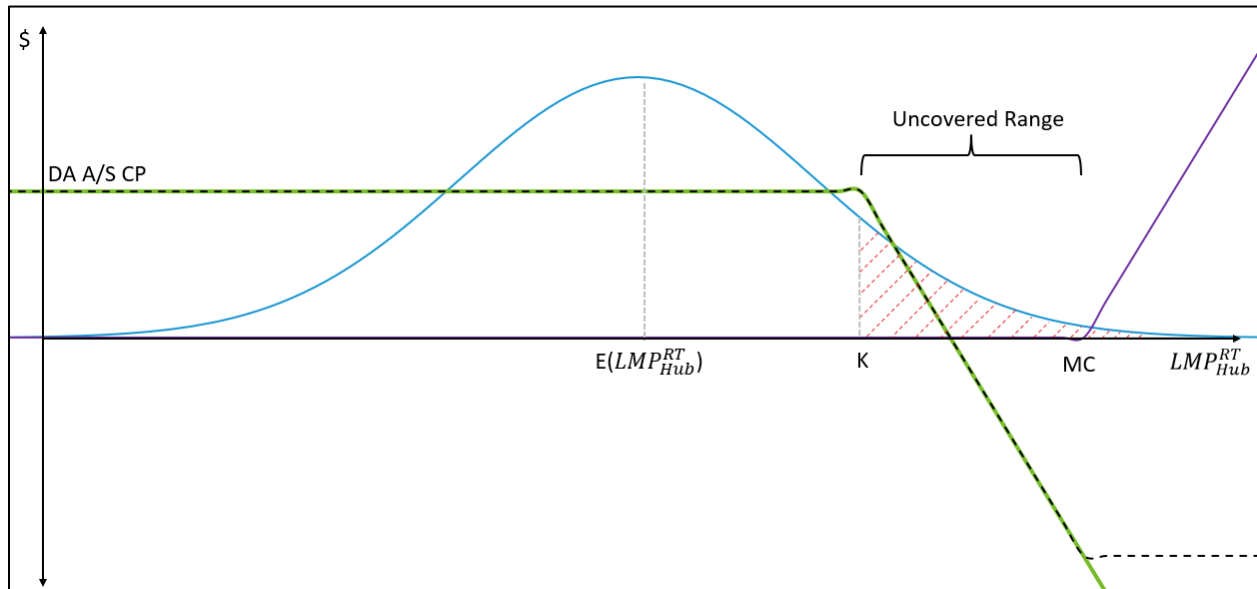
Indeed, both approaches are somewhat conservative in that they treat risk as something participants evaluate asset-by-asset and over short horizons. In practice, resource owners manage risk at the portfolio level and over longer horizons, so diversification and intertemporal balancing can reduce the risk that must be priced into any single asset's DA A/S offer in any given hour. While participant risk tolerance and hedging capability are heterogeneous and not directly observable, we use these two transparent benchmark frameworks to bound plausible risk-premium levels and to evaluate whether risk premiums can materially impact market outcomes.

We start by laying out the underlying cost components of a DA A/S award, before turning to how the Sharpe and CVaR frameworks translate risk exposure into a premium. Recall from Section 3.1.3 that the primary cost associated with a DA A/S award is the expected closeout, which represents the probability-weighted charge that a resource could otherwise avoid by not taking on a DA A/S award. Other costs include the fuel-related costs incurred by a subset of DA A/S providers (gas and energy storage); under this design, these are referred to as avoidable input costs.⁸⁴

Risk arises for resources with DA A/S awards because these obligations exchange a fixed premium (the DA A/S clearing price) for exposure to uncertain (and potentially severe) real-time closeout charges. An illustrative example that describes some of the important factors related to this risk is presented in Figure 6-5 below. In this figure, the x-axis represents possible values of the real-time LMP and the y-axis represents payoff in dollars.

⁸⁴ For more information about the various components of a DA A/S offer, see Section 3.1.3.

Figure 6-5: Payoff Diagram



The payoff associated with the DA A/S award is shown by the green line; the resource receives the DA A/S clearing price until the real-time LMP exceeds the strike price, K , at which point it decreases one-for-one with the real-time LMP. This figure also incorporates the resource's payoff from producing energy in real time (purple line); there is no payoff until the real-time LMP exceeds the asset's short-run marginal cost, denoted MC , at which point it increases in value one-for-one with the real-time LMP.⁸⁵ Finally, the figure also shows the combined payoff of a DA A/S award *and* producing energy in real time (black dashed line). The combined payoff matches the DA A/S payoff until the real-time LMP exceeds the asset's marginal cost; once the unit is in merit, incremental real-time energy margins offset the increasing closeout exposure if the unit can run (i.e., is not on outage), so the combined payoff becomes approximately flat over that range.⁸⁶

While the payoff will vary by resource depending on its marginal cost and its performance, the resource depicted in the figure above is one whose short-run marginal cost exceeds the strike price and so is not able to offset the closeout charge with real-time energy production through a wide range of possible real-time LMPs (labeled as "Uncovered Range" in the figure). In fact, this resource begins incurring a loss at some value of the real-time LMP above the strike price, and even when the resource produces energy, it does not eliminate the loss but instead only prevents it from increasing. More generally, the figure highlights that DA A/S exposure is most acute in states where

⁸⁵ The dollar-for-dollar increase in the real-time margin holds when the resource is available to run once prices exceed short-run marginal cost.

⁸⁶ For exactly the reason outlined in footnote 85, the apparent hedge in combined payoffs holds when the resource is available to run once prices exceed short-run marginal cost. Because outages occur with nonzero probability, there are high-price states in which the unit cannot produce and therefore cannot offset closeout exposure; these states drive residual downside risk and contribute to both overall profit volatility and tail outcomes.

real-time prices are high, but the resource cannot (or does not) provide offsetting real-time energy—whether because it remains out of merit or because it is unavailable.

The risk calculation that a resource owner makes in relation to taking on a DA A/S award depends on numerous factors captured in the illustrative example above (e.g., the expected DA A/S clearing price, the strike price, the resource’s marginal cost, the distribution of real-time LMPs) as well as other considerations not shown (e.g., portfolio-level risk tolerances and resource outage risk).

Different methodologies formalize the tradeoff between risk and return in different ways. In this section we utilize two common methodologies—the Sharpe ratio, which is based on overall profit variability, and CVaR, which focuses on tail losses (extreme downside exposure)—to estimate benchmark measures of risk associated with a DA A/S award.⁸⁷ We then perform market simulations that make use of these risk estimates and compare the results from these simulations to the one based on actual participant offers. This comparison allows us to assess the extent to which market outcomes may reflect competitive offers that incorporate benchmark risk premiums.⁸⁸

Sharpe Ratio

Under the Sharpe ratio approach, the risk premium for selling DA A/S is determined by comparing risk-adjusted expected profits from two alternatives: (i) selling both DA A/S and real-time energy, and (ii) selling real-time energy only. Risk is summarized by the *standard deviation of net revenues*, and the guiding condition is that the Sharpe ratio (expected profit divided by standard deviation) from DA A/S participation must be at least as large as that of the next-best alternative. We compute expected net revenues and profit volatility under each alternative using simulated real-time price distributions (derived from ISO-NE’s Gaussian Mixture Model), along with resource-specific outputs such as marginal costs and outage rates. The DA A/S offer price is then solved as the minimum offer that equalizes these risk-adjusted returns.⁸⁹

Within this framework, the Sharpe-based risk premium is the increment above fair value, defined as expected closeout costs plus any avoidable input costs (AIC), required to satisfy the Sharpe condition. This framework yields a clear decomposition of competitive offers. All suppliers must recover expected DA A/S closeout costs (and any avoidable fuel or storage costs), while a positive risk premium appears only if DA A/S participation *increases* profit volatility relative to real-time-only operation.

Importantly, low volatility does not necessarily imply low downside exposure. A resource with a very high short-run marginal cost, for example, may have stable profits simply because it is rarely in merit and seldom operates. Under a Sharpe metric, DA A/S participation may appear to add little incremental variance. Yet such a resource still faces large closeout charges in high-price states

⁸⁷ The distinction matters most in periods of scarcity, where non-linear price behavior drives economic risk.

⁸⁸ Our risk premium metrics are intended to capture certain salient features of the exposure faced by DA A/S suppliers. These approaches do not capture the likely wide range of risk tolerances across market participants.

⁸⁹ We follow the approach developed during the DASI stakeholder process: https://www.iso-ne.com/static-assets/documents/2023/06/a03a_mc_2023_06_06_dasi_competitive_offer_formulations_memo.pdf

and has little operational ability to profitably offset them through real-time production. Conversely, flexible gas or storage resources may exhibit higher gross variability but also stronger natural hedges—profits from real-time operation that rise exactly when closeouts are large—so that DA A/S participation can leave their overall volatility unchanged or even lower, satisfying the Sharpe condition with little or no additional premium.

In Sharpe-ratio terms, the key question is therefore whether adding the DA A/S position increases the overall dispersion of profits relative to real-time-only operation; that increase can be material even if the Uncovered Region in Figure 6-5 is narrow, depending on how frequently the unit is out of merit in tight hours and how often outages prevent the unit from running when prices are high.

As mentioned above, we performed the following simulation:

- **Sharpe:** a scenario in which all DA A/S constraints are ‘turned on’ but DA A/S offers are based on expected closeout, any avoidable input costs, and a resource-specific risk premium derived using the Sharpe methodology outlined above.

Table 6-4 below provides a high-level comparison of this Sharpe scenario to the DA A/S scenario (initially presented in Section 4.2).

Table 6-4: Comparison to Outcomes with Competitive Offers plus Sharpe Ratio Risk Premia

Category	DA A/S (\$M)	Sharpe (\$M)	Delta (\$M)	Delta (%)
DA Energy	\$11,153	\$11,194	\$40	0.4%
<i>LMP</i>	\$10,127	\$10,081	-\$47	-0.5%
<i>FER Price</i>	\$1,026	\$1,113	\$87	8.5%
DA A/S	\$261	\$259	-\$2	-0.9%
<i>Credits</i>	\$453	\$450	-\$4	-0.8%
<i>Closeouts</i>	-\$192	-\$191	\$1	-0.7%
Total Charges/Credits	\$11,415	\$11,453	\$38	0.3%
Cost of Incremental RT Energy	\$136	\$138	\$1	0.9%
Total Cost/Revenue Change	\$11,551	\$11,590	\$39	0.3%

The simulation results using the Sharpe approach for calculating risk show modest cost increases relative to the simulation based on participant offers. The cost increases are most notable for the FER-related credits (labeled ‘FER Price’ in Table 6-4), which increases by \$87 million. However, these increases are partially offset by a decrease in LMP-based payments of \$47 million, resulting in a modest increase in total day-ahead energy market payments (\$40 million). Payments in the DA A/S market and the real-time energy market were largely unchanged, and the result was an overall increase in costs of \$39 million.

As an additional diagnostic, we isolate the **12 highest-cost days** (largely clustered in multi-day stress events) that together account for roughly half of the incremental first-year DA A/S costs. In this subset, costs under the participant-offer baseline (the DA A/S scenario) amount to \$1,900 million (\$158 million per day) compared to \$2,017 million (\$168 million per day) under Sharpe-based competitive offers, implying that costs on these 12 days were 5.8% below what they would have been had active participants offered according to our Sharpe-based competitive benchmarks. By contrast, across the remaining days of the year, DA A/S costs were \$9,651 million (\$27.50

million per day) versus \$9,573 million (\$27.27 million per day) under the Sharpe-based competitive benchmark, indicating that in normal conditions, participants are broadly consistent with Sharpe-implied premia.

CVaR

A CVaR (Expected Shortfall) approach reframes the same problem in explicitly *tail-risk* terms. Instead of focusing on overall revenue volatility, risk is defined as the average loss in the worst 5 percent of outcomes. For DA A/S positions, these tail losses arise in scenarios where real-time prices exceed the strike price and the resource is unable to offset the resulting closeout charge through real-time operation, leading to losses. This can occur either because the unit is economically out-of-merit (e.g., due to high short-run marginal cost) or because it is physically unavailable (e.g., on outage). In both cases, the defining feature of tail risk is the lack of an effective operational hedge precisely in the states where closeout charges are largest.

Under this approach, tail losses are computed directly from simulated profit distributions, and the risk premium is set as the incremental compensation required to cover the incremental economic capital needed to absorb those losses. A fixed capital charge rate converts required tail-risk capital into a \$/MWh premium. Relative to a Sharpe-ratio method, CVaR places much greater weight on asymmetric downside exposure, focusing on states where high RT LMPs coincide with an inability to hedge closeout charges through real-time production. These states arise not only from physical outages, but also from high short-run marginal costs that keep units out of merit. By explicitly conditioning on such stress scenarios, CVaR captures economically relevant risk that variance-based measures tend to smooth over, making it well suited for participants whose binding constraints are liquidity, collateral, or internal risk limits defined by severe but infrequent losses, rather than by average profit volatility.⁹⁰

In CVaR terms, the Uncovered Region in Figure 6-5 matters disproportionately (especially when coincident with resource outages) because it determines the worst-tail outcomes—high-price intervals in which the closeout exposure is large, and the operational hedge is ineffective.

As mentioned above, we performed the following simulation:

- **CVaR:** a scenario in which all DA A/S constraints are ‘turned on’ but DA A/S offers are based on expected closeout, any avoidable input costs, and a risk premium derived using the CVaR methodology outlined above.

Table 6-5 below provides a high-level comparison of this CVaR scenario to the DA A/S scenario (initially presented in Section 4.2).

⁹⁰ The tradeoff is complexity: CVaR requires careful specification of tail thresholds, capital charges, and, for resources with avoidable input costs, a specification of the dependence between various profit components like RT LMP and input prices.

Table 6-5: Comparison to Outcomes with Competitive Offers plus CVaR Risk Premia

Category	DA A/S (\$M)	CVaR (\$M)	Delta (\$M)	Delta (%)
DA Energy	\$11,153	\$11,247	\$94	0.8%
<i>LMP</i>	\$10,127	\$10,059	-\$69	-0.7%
<i>FER Price</i>	\$1,026	\$1,188	\$162	15.8%
DA A/S	\$261	\$287	\$26	9.9%
<i>Credits</i>	\$453	\$477	\$24	5.3%
<i>Closeouts</i>	-\$192	-\$190	\$2	-0.9%
Total Charges/Credits	\$11,415	\$11,534	\$119	1.0%
Cost of Incremental RT Energy	\$136	\$137	\$1	0.5%
Total Cost/Revenue Change	\$11,551	\$11,671	\$120	1.0%

Compared to the DA A/S scenario, the simulation results based on the CVaR approach depict overall cost increases. The largest cost increase occurs in the FERP-based payments (labelled ‘FER Price’ in Table 6-5), which rose by \$162 million. However, these cost increases were partially offset by a reduction in LMP-based payments of \$69 million. The combined impact was an increase in day-ahead energy market payments of \$94 million relative to the DA A/S scenario. Unlike the Sharpe scenario, costs also increased in the DA A/S market under this approach, rising by \$26 million. With the minor increase in real-time energy payments (\$1 million), the overall increase in costs amounts to \$120 million.

We also perform the same **high-risk-day breakout** under the CVaR framework, which by construction places greater weight on the severe but infrequent outcomes that characterize stressed system conditions. On the 12 highest-incremental-cost days, costs under the participant-offer baseline (the DA A/S scenario) amount to \$1,900 million (\$158 million per day) compared to \$2,051 million (\$170.95 million per day) under CVaR-based competitive offers, implying that costs on these 12 days were 7.4% below what they would have been had active participants offered according to our CVaR-based competitive benchmarks. On the remaining days of the year, DA A/S costs were \$9,651 million (\$27.50 million per day) compared to \$9,619 million (\$27.41 million per day) under the CVaR-based competitive benchmark, again suggesting close alignment in normal periods but a materially larger gap during system stress.

Over the full year, simulated costs fall slightly below the costs produced by the Sharpe- and CVaR-based competitive benchmarks. That full-year comparison, however, is driven primarily by a small number of high-cost stress days: on the 12 highest-incremental cost days, participant-offer outcomes were 5.8% below the Sharpe benchmark and 7.4% below the CVaR benchmark, while on the remaining days, participant-offer outcomes were closely aligned with both benchmarks. This pattern suggests that observed offers were broadly consistent with competitive, risk-adjusted behavior in normal conditions, and somewhat below these benchmark levels during stressed conditions. At the same time, both the Sharpe and CVaR frameworks are conservative benchmarks because they evaluate risk largely on a unit-by-unit basis and over relatively short horizons and therefore do not fully reflect the benefits of diversification across assets or intertemporal risk management within participant portfolios. Accordingly, the fact that participant-offer outcomes fall at or below these benchmarks is consistent with offers reflecting “reasonable” risk premia.

Section 7

Mitigation Performance

This section evaluates whether observed mitigation outcomes during the first year of DA A/S market operations are consistent with the intended two competing objectives: limiting the risk that uncompetitive offers materially affect market outcomes, while avoiding unnecessary intervention of offers based on a resource's legitimate competitive costs; with particular attention to the frequency, context, and system conditions under which mitigation occurred.

Key Takeaways

Overall, mitigation outcomes observed during the first year of DA A/S market operations are largely consistent with the stated objectives of the mitigation framework. Mitigation occurred infrequently, was generally limited to circumstances where offers both materially exceeded benchmark expectations and had a measurable effect on clearing prices, and did not appear to constrain competitive offer behavior during periods of heightened system stress.

One notable exception arises when price impact thresholds fell below \$3/MWh, which occurs during times when system conditions are generally unstressed and market power is not a concern. Almost thirty-percent of mitigations occurred under these conditions. The ISO plans to address as part of their DA A/S market enhancements work in 2026 by incorporating a \$3/MWh price impact floor, a sensible measure which will address these observed instances of over-mitigation.

As described in the ISO's filing, the mitigation framework is explicitly designed to intervene only in clear and impactful instances of uncompetitive behavior.⁹¹ To achieve this balance, the DA A/S mitigation framework applies a sequenced evaluation consisting of a conduct test to identify offers that materially exceed benchmark levels, a price impact test to assess whether such offers meaningfully affect market clearing prices, and mitigation that is limited to offers failing conduct test thresholds. This structure reflects a deliberate design choice to preserve pricing flexibility under most conditions while providing targeted safeguards when competitive outcomes may otherwise be distorted.

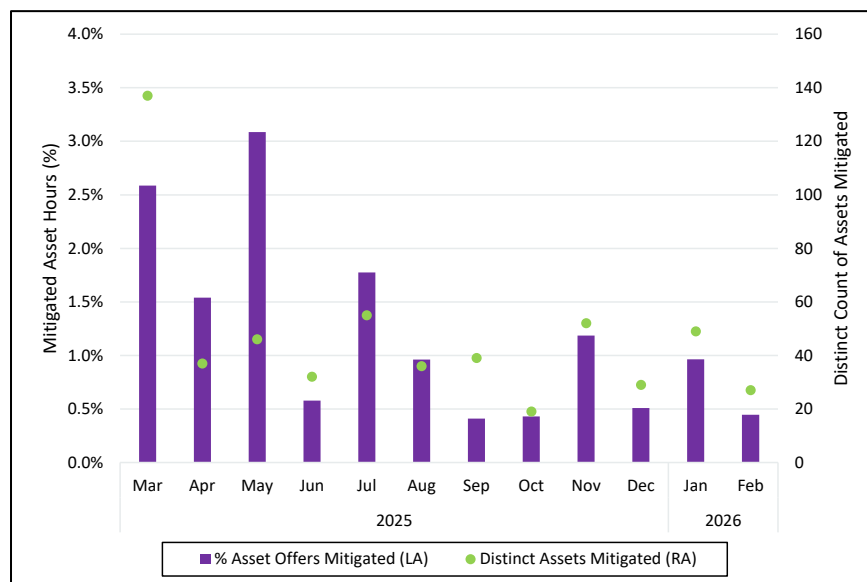
Frequency of Mitigation

In general, there has been a low frequency of DA A/S mitigation indicating that mitigation has not played a prominent role in determining market outcomes. The occurrence of DA A/S mitigation can

⁹¹ See Dr. Alivand's testimony in https://www.iso-ne.com/static-assets/documents/100004/rev_to_est_jointly_optimized_day-ahead_mkt_for_energy_and_ancillary_services.pdf

be seen in Figure 7-1 below, which shows the percentage of DA A/S offers that were mitigated on the left axis (LA) and the count of the distinct assets that were mitigated on the right axis (RA).⁹²

Figure 7-1: DA A/S Mitigations



Over the course of the first year, 1.2% of all asset-product-hours were mitigated. The count of distinct assets that were mitigated in any month ranged from 19 in October 2025 to 137 in March 2025.⁹³ It is likely that a growing familiarity with the market design reduced both the frequency of mitigation and the number of assets that were mitigated.

Mitigation Performance During Periods of System Stress

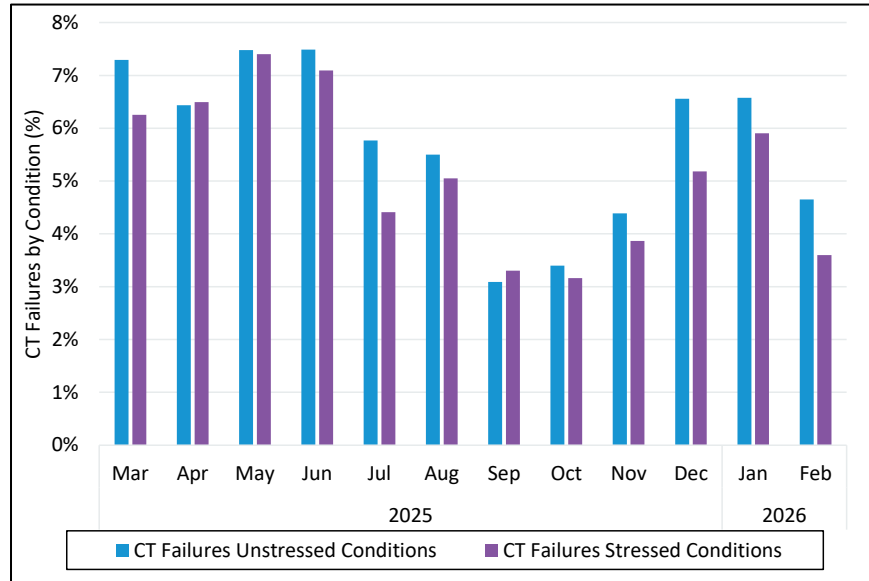
The IMM has found that, in general, participants do not increase their offers beyond the conduct test threshold more frequently when the system is stressed, and, if anything appear more likely to remain within conduct test thresholds during these periods. This can be seen in Figure 7-2 below, which compares conduct test failure rates during periods of stressed system conditions and unstressed periods.⁹⁴

⁹² Given that one asset can make offers on up to four DA A/S products per hour, this percentage represents the count of mitigated asset-product-hours relative to the total count of asset-product-hours in the period.

⁹³ For example, in October, the 19 distinct assets could have been mitigated on different days or the same day, and in different hours or the same hour. Using the combination of the percent of all asset-offers, along with the distinct number of assets mitigated in a month, explains the market-wide impact of mitigation.

⁹⁴ Hourly reserve margins are defined as the difference between ex-post capability and the associated FRS requirement. If any of the three reserve margins was in the bottom 10th percentile for the month, that hour was flagged as a stressed condition hour. Otherwise it is considered unstressed.

Figure 7-2: Conduct Test Failures Across FRS Products

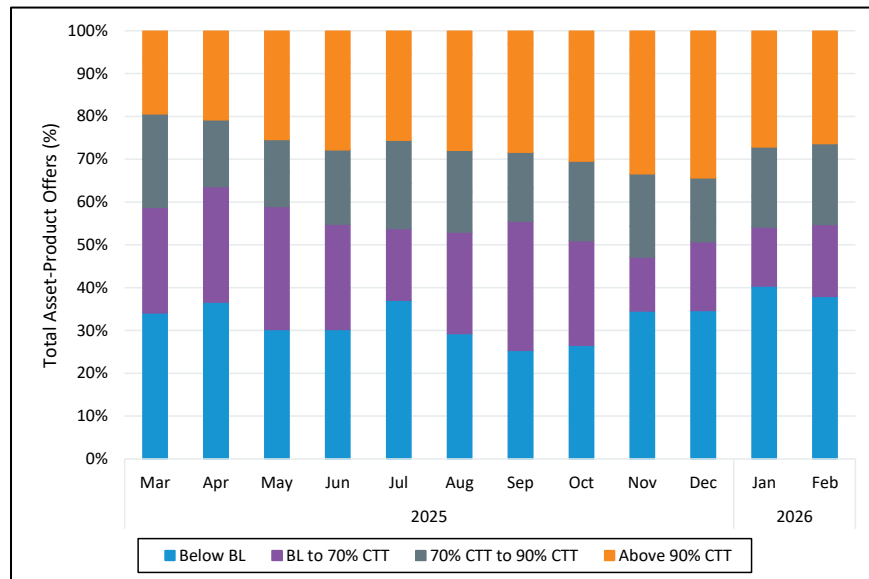


The results indicate that conduct test failure rates exhibit little change—and in several months are modestly lower—during stressed system conditions. One plausible explanation is that the conduct test threshold prices do a reasonable job defining the upper limit for competitive price ranges. Another plausible explanation is that participants adjust their offers to avoid failing the conduct test. As a result, participants may limit conduct test exposure rather than risk mitigation.

Participant Offers Relative to Mitigation Values

Figure 7-3 below represents participant offer bands across all products relative to benchmark levels and the conduct test threshold.

Figure 7-3: Offers Relative to Mitigation Values



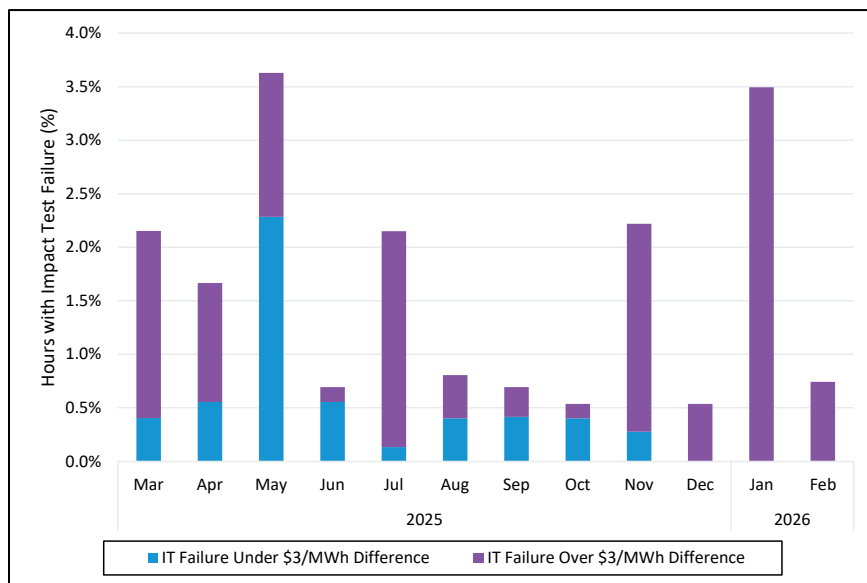
The blue and purple categories, representing offers below the benchmark level or only modestly above it, account for 55% of offers. The gray category, representing offers between 70% and 90% of the conduct test threshold, accounts for 18% of offers. These offers approach the conduct test threshold without exceeding it and may reflect situations in which participants incorporate their own assessment of system conditions or operational risk into pricing decisions, resulting in offers that move meaningfully above benchmark levels while remaining below the conduct test threshold. This behavior is consistent with the intended design of conduct test threshold multipliers, which allow some upward pricing flexibility while discouraging excessive departures from benchmark levels.

The remaining 27% of offers fall at or above 90% of the conduct test threshold, including approximately 6% of offers that fail the conduct test. Offers above the conduct test threshold that occur on days with impact test failures are subject to mitigation and are reduced to benchmark levels when mitigation occurs. Participants whose offers fall into these higher bands may have legitimate concerns that existing conduct test thresholds do not fully reflect their operational or business conditions. In such circumstances, participants are encouraged to engage with the IMM to discuss potential adjustments, including benchmark overrides, as described in Appendix A of the ISO-NE Tariff.

Over-mitigation

One area where the mitigation design shows fault arises when price impact thresholds fell below \$3/MWh. In these instances, mitigation tended to occur under relatively benign system conditions when market power is typically not a concern, suggesting a risk of over-mitigation that does not advance the core objectives of the framework. These outcomes indicate that very low impact thresholds are less effective at distinguishing between competitively meaningful and inconsequential price effects. Instances of impact test failures at impact prices below \$3/MWh (blue) and above \$3/MWh (purple) are shown in Figure 7-4.

Figure 7-4: Percent of Hours with Impact Test Failure



During the first year, there were impact test failures in 1.6% of hours, leading to mitigation on 63 days. Of those hours, 28% occurred when the impact test threshold and evaluated price difference were below \$3/MWh. Hours with price impact violations occurring at thresholds of \$3/MWh or less were associated with expected real-time LMPs below \$29/MWh.⁹⁵ This pattern suggests these conduct/impact violations occurred during relatively benign system conditions, when the exercise of market power was less likely to raise concerns. For reference, in hours where the violations occurred at thresholds greater than \$3/MWh, the expected real-time LMP averaged \$111/MWh.

⁹⁵ The ISO started producing an expected real-time LMP as part of the implementation of the DA A/S market.

Section 8

GMM Performance

This section assesses the performance of the ISO’s statistical model that is used to estimate several key values associated with the DA A/S market.

Key Takeaways

Over the first year of DA A/S, the GMM understated real-time LMPs on average. Model performance reflected systematic under forecasting bias, with observed values frequently falling in the upper percentiles of the predictive distributions. This bias carried through to expected closeout values, which were also understated relative to realized outcomes.

We encourage the ISO to continue to invest in its modeling tools and processes to ensure that expected real-time energy prices and closeout costs better track prevailing market conditions.

8.1 Expected Real-time LMP

To calculate key DA A/S market values, the ISO developed a statistical model of real-time LMPs that depends on a set of explanatory variables known in advance of the day-ahead market (e.g., load forecast, gas price).⁹⁶ The statistical model is a Gaussian Mixture Model (GMM), which produces a set of normal (i.e., Gaussian) distributions whose means and variances change depending on the values of these explanatory variables.

The GMM distributions are used to compute both the expected real-time LMP, which is used to set the Strike Price, and the expected closeout charge, which forms a key part of a resource’s benchmark level that is used in DA A/S mitigation. These values represent means that are determined by integrating over the full range of price outcomes. Therefore, these values are not expected to match realized outcomes on an hour-by-hour basis. However, for a well-calibrated model, the *average* expected values should converge to the *average* realized values over a sufficiently large sample period.

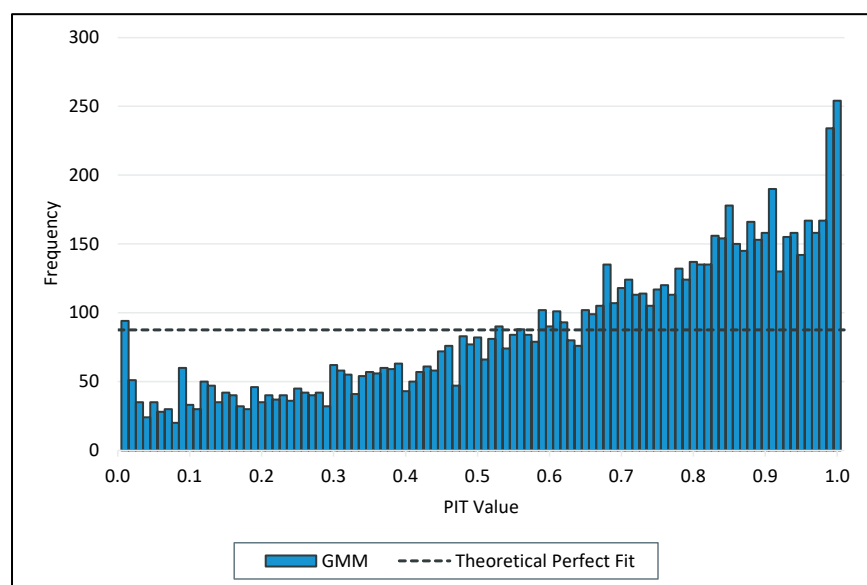
Over the first year of the DA A/S market, we found that the GMM tended to underestimate the real-time LMP. Over this period, the average expected real-time LMP from the GMM was \$60.06/MWh, while the average realized real-time LMP was \$67.63/MWh, indicating a \$7.57/MWh average underprediction bias.

This bias is consistent with evidence that the GMM underestimated the right tail of the real-time LMP distribution. To evaluate the fit of the GMM distributions (which produce the expected real-time LMP) to the true distribution of observed pricing outcomes (realized real-time LMP), we use a probability integral transform (PIT) histogram. The PIT value is defined as the percentile of the

⁹⁶ More information about the model that the ISO uses to forecast the real-time LMP can be found in the ISO’s Day-Ahead Ancillary Services Monthly Real-Time LMP Modeling Memo, available at <https://www.iso-ne.com/isoexpress/web/reports/pricing/-/tree/DA-A/S-monthly-memo>.

realized outcome under the GMM forecast distribution.⁹⁷ Figure 8-1 shows the histogram of PIT values for all hours during the first year of DA A/S.

Figure 8-1: Probability Integral Transform (PIT) Histogram, All Hours



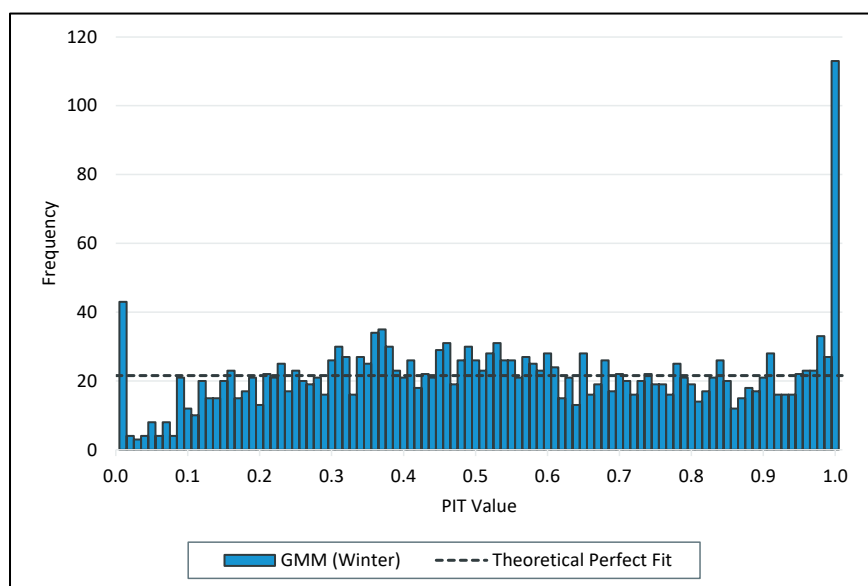
The empirical distribution of PIT values in Figure 8-1 provides a visual assessment of the model fit. The dashed line represents the uniform expected height of the histogram bars for a theoretical model that is perfectly well-calibrated at every percentile.⁹⁸ In contrast, the GMM distribution exhibits a pronounced right skew, with the bulk of the histogram mass falling in the higher percentiles. In particular, approximately 250 hours fell above the 99th percentile of the GMM distribution, over twice as many as expected under a model that perfectly captures the likelihood of observed outcomes. This heavy concentration of prices at high PIT values (and corresponding deficiency of observations at low PIT values) suggests that the GMM understated the probability of high-price outcomes.

Seasonal analysis shows similar patterns throughout most of the year, except for winter. Figure 8-2 shows that winter PIT values were more consistent with a uniform distribution in the middle percentiles but exhibited pronounced spikes in both tails. This increased frequency of observations at PIT ~ 1 ($n=113$) and PIT ~ 0 ($n=43$) indicates that, during winter, the model produced distributions that were too narrow to capture the actual variability in real-time LMPs. As a result, the model frequently underpredicted extreme high-price outcomes. It also occasionally produced severe overpredictions of low-price outcomes. Of these 156 extreme percentile outcomes, 51% occurred during Winter Storm Fern.

⁹⁷ For example, if an observed real-time LMP falls at the 50th percentile of the hour's GMM distribution, its PIT value is 0.5.

⁹⁸ A model is well-calibrated if, for any predicted probability, p , the empirical probability of the event actually occurring matches p . In the language of PIT values, a model is well-calibrated at the 50th percentile if 50% of observations have PIT values less than or equal to 0.5 over a sufficiently large sample, i.e., if 50% of the histogram mass falls below PIT 0.5.

Figure 8-2: PIT Histogram, Winter Hours



8.2 Expected Closeouts

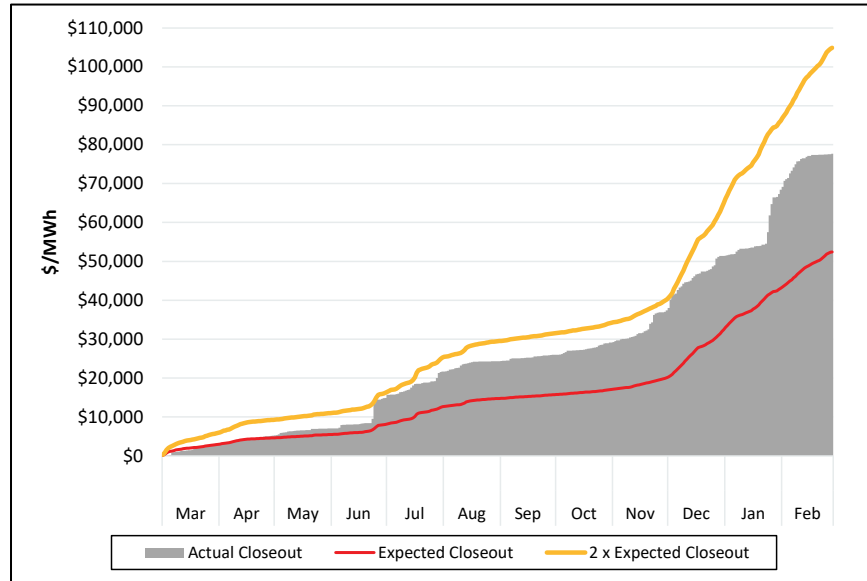
The ISO computes expected closeout charges as the probability-weighted average of potential closeout outcomes, with these probabilities derived from the GMM. Given the model’s tendency to underestimate the upper tail of real-time prices, this bias is expected to be carried through to underestimate expected closeouts as well.

Consistent with this expectation, we found that the GMM underestimated the expected closeouts relative to realized values when viewed on a cumulative basis. This is shown in Figure 8-3 below, which shows the cumulative actual closeout with gray bars and the cumulative expected closeout value produced by the GMM as a red line.⁹⁹ The figure also depicts, in orange, a value that is twice the expected closeout (labeled as ‘2 x Expected Closeout’); this represents the expected closeout portion of the conduct test threshold price that is used in mitigation.¹⁰⁰

⁹⁹ In order to illustrate GMM performance, this expected closeout series does not include any IMM overrides.

¹⁰⁰ For more information about the conduct test threshold price and mitigation, see Section 3.1.4.

Figure 8-3: Actual and Expected Closeouts, Cumulative



We can see that the cumulative actual closeouts, which tend to be more volatile, exceeded the cumulative ISO-produced expected closeouts by a significant margin at the end of the first year of the DA A/S market. Actual closeouts totaled \$78,000/MWh while expected closeouts totaled only \$52,000/MWh. This means that a hypothetical asset that cleared one MWh of DA A/S awards in every hour would have incurred a loss of over \$25,000 if DA A/S clearing prices had been exactly equal to the expected closeouts from the ISO's model.¹⁰¹

To account for estimation error, as well as for reasonable variation in participant expectations of real-time outcomes and in risk premiums, the DA A/S offer mitigation design allows participants to offer up to twice the expected closeout without triggering mitigation. We can see that the cumulative twice expected closeout series does exceed the cumulative actual closeout series at the end of the first year, reaching a year-end total of \$105,000/MWh.

These findings have two important implications. First, when the model produces Strike Prices below prevailing market expectations, the resulting expected closeout values will also be lower, which may prompt the IMM to adjust mitigation values to correct this misalignment, potentially increasing offer prices and day-ahead market costs.¹⁰² Indeed, the IMM performed such adjustments during many high-stress days. Second, implementing a Strike Price floor—consistent with our recommendation to better align the strike price with the short-run marginal costs of

¹⁰¹ It is worth noting that DA A/S clearing prices are not expected to equal the expected closeout for a variety of reasons, one significant cost driver to date being that clearing prices reflect significant opportunity costs.

¹⁰² The relationship between strike price levels and market outcomes is nuanced and requires further study. In particular, while lower strike prices relative to prevailing market conditions increase expected closeout costs and likely increases overall day-ahead costs, however this effect is at least partially offset by higher realized closeout costs.

resources providing ancillary services—offers a meaningful secondary benefit by eliminating forecasting errors below the marginal cost of a combustion turbine.

Even with this change, we continue to encourage the ISO to invest in its modeling tools and processes so that expected real-time energy prices and closeout costs more closely reflect prevailing market conditions. When the expected real-time LMP (plus the \$10/MWh adder) exceeds the proposed floor and determines the Strike Price, it is important that these inputs to option pricing remain aligned with current market conditions.

Section 9

Market Performance Metrics

While previous sections evaluated market costs and competitiveness, this section assesses market performance. Specifically, this section focuses on how well the day-ahead market is preparing the system for what is needed in real time. Consequently, focus in this section is given to price convergence (as an indicator of market efficiency), out-of-market actions, and Net Commitment Period (NCPC) costs. We conclude with an assessment of how DA A/S impacts wholesale revenues streams and potential implications for cost recovery allocation between the E&AS and capacity markets.

Key Takeaways

The first year of DA A/S was associated with a modest increase in the average day-ahead price premium, rising to \$3.81/MWh from \$1.18/MWh, while the median remained largely unchanged, indicating that a small number of high-price events, particularly during stressed periods like July 2025 and January 2026, drove the increase.

Out-of-market commitments have been infrequent in recent years, even before DA A/S, and in the past year have further declined slightly and remained rare.

DASI did not lead to a clear reduction in day-ahead NCPC, as higher revenues from FER and reserves were offset by lower energy prices and ongoing cost recovery needs for marginal units. While DASI may reduce NCPC by avoiding some manual RAA commitments, these potential savings are highly uncertain and likely modest relative to an upper-bound estimate of approximately \$35 million annually. Real-time NCPC declined in categories associated with out-of-merit actions, suggesting improved system preparedness, but the overall impact is relatively small.

Over time, DA A/S revenues may therefore reduce the “missing money” that some resources seek to recover through the capacity market. This is particularly the case for combustion turbine resources. As a result, these revenues are expected to influence capacity-market offer behavior and, ultimately, capacity-market outcomes. Future estimates of energy and ancillary services revenues should also affect Net CONE estimates and the setting of the capacity market’s administrative demand curve. These longer-run effects are not measured in our first-year incremental-cost estimates but are important to understanding the design’s broader economic implications.

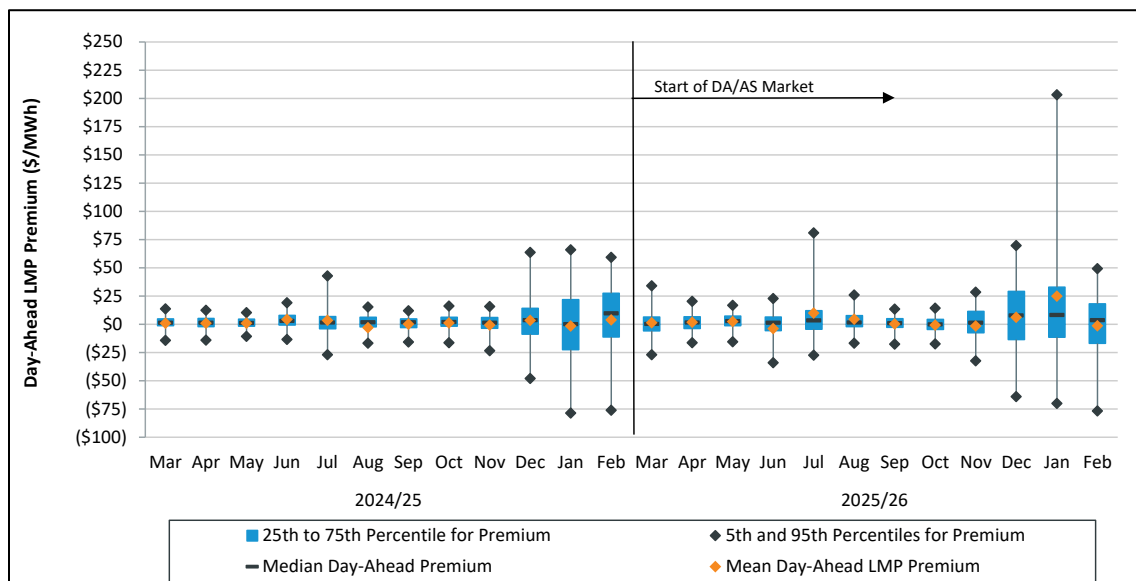
9.1 Price Convergence

Price convergence describes the degree to which prices in the day-ahead and real-time markets align. It is commonly used as an indicator of market efficiency, defined here as achieving the necessary real-time resource commitments at the lowest possible cost. Strong price convergence can indicate that the day-ahead market is effectively anticipating real-time conditions to facilitate efficient and reliable scheduling outcomes.

While both the day-ahead and real-time markets are now co-optimized markets that procure energy and operating reserves, they differ in important ways that can impact price convergence. Reserve procurement in the day-ahead market is based on voluntarily-submitted ancillary services offers, while procurement in the real-time market considers all reserve-capable resources (i.e., is not strictly voluntary) and determines reserve clearing prices solely based on opportunity costs (i.e., there are no reserve offers). Additionally, the incorporation of the Forecast Energy Requirement Price (FERP) as a second price for (physical) energy adds complexity to what had previously been a comparison simply between LMPs.¹⁰³

LMP convergence can be seen in Figure 9-1, which shows the distribution of the day-ahead price premium (i.e., day-ahead LMP minus real-time LMP) at the Hub by month between March 2024 and February 2026 using a box-and-whiskers diagram. This figure also shows the average monthly day-ahead LMP premium (orange marker).

Figure 9-1: Day-Ahead vs. Real-Time LMP Convergence



The day-ahead premium averaged \$3.81/MWh over the first year of DA A/S, up from \$1.18/MWh in the year prior. However, the median day-ahead premium remained similar, increasing from \$1.84/MWh to \$1.93/MWh over the same period. The difference between the average and median highlights that the day-ahead premium was right-skewed, with some high observations pulling the mean up. This can be seen in the figure above; in fact, the average day-ahead premiums in July 2025 and January 2026 were the two months with the highest premiums since the beginning of the Standard Market Design.

¹⁰³ ISO-NE expected that, over time, the day-ahead and real-time LMP would converge under this new market design as load-serving entities cleared more demand in the day-ahead market to take advantage of lower day-ahead LMPs when the FERP bound. See pages 54-56 of the testimony of Ben Ewing in support of DASI contained within the ISO's filing to FERC, which is available here: https://www.iso-ne.com/static-assets/documents/100004/rev_to_est_jointly_optimized_day-ahead_mkt_for_energy_and_ancillary_services.pdf.

While the day-ahead premium increased in the year following the implementation of DA A/S, it is important to consider the factors that contribute to a day-ahead premium:

- Under DA A/S, the day-ahead market produces a more robust and flexible operating plan for real time than with the previous market construct. The cost of procuring this additional flexibility is reflected in day-ahead energy and ancillary service prices.
- Because not all operating reserve capability is offered into the day-ahead market, there can be less economic capacity available to meet load and reserve requirements than in real time. Co-optimization can further raise day-ahead LMPs when efficient generators are used to satisfy reserve requirements rather than energy, resulting in higher-cost resources setting the price. This effect becomes more pronounced under stressed conditions, when the energy supply curve is steeper.
- Renewable resources often offer in a way that results in only a portion of expected real-time output clearing day-ahead. As a result, higher-cost generation may be dispatched in the day-ahead market to meet the FER (also impacting the LMP) and later displaced by lower-cost renewable generation in real time.
- Increased long-lead time commitments and stronger performance incentives under DA A/S place downward pressure on real-time LMPs, reducing reliance on higher-cost real-time-only generation.

9.2 Out-of-Market Actions

Out-of-market actions can reflect both market performance and reliability. If DA A/S improves the day-ahead operating plan, one expected benefit is fewer supplemental commitments through the reserve adequacy analysis (RAA) process or manual operator actions.¹⁰⁴ Because these actions are infrequent, annual averages can obscure the magnitude of actions taken on stressed days. We therefore report a time series, highlighting commitments on the top 12 highest cost DA A/S days¹⁰⁵, all of which occurred during Winter Storm Fern.

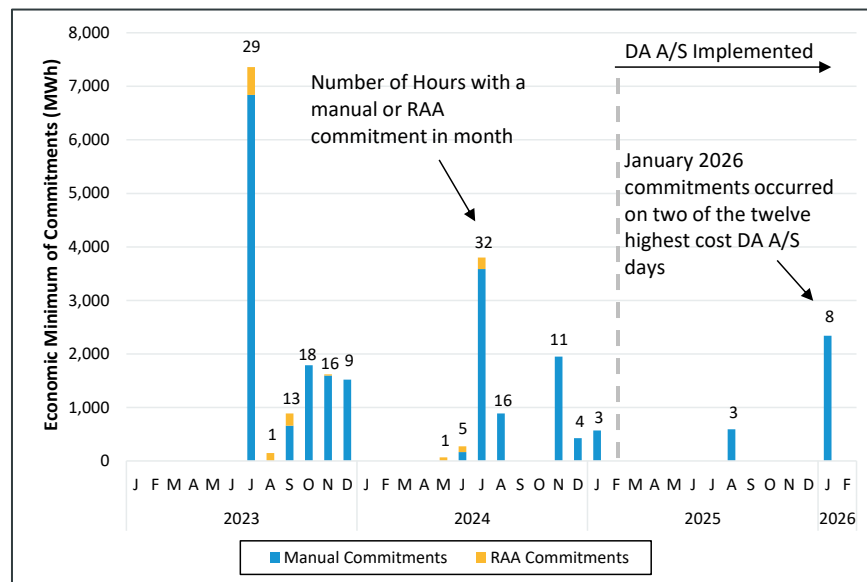
Our evaluation indicates that DA A/S has potentially reduced manual commitments and RAA commitments, although the impact is slight due to the low quantity of these committed MWs pre-DA A/S.¹⁰⁶

¹⁰⁴ RAA commitments include commitments made post-day-ahead clearing to ensure adequate reserves. These commitments can happen during the operating day or the previous day after the day-ahead market is run. For more information, see ISO-NE operating procedure titled *Perform Reserve Adequacy Analysis*, available here: https://www.iso-ne.com/static-assets/documents/rules_proceeds/operating/sysop/rt_mkts/sop_rtmkts_0050_0010.pdf

¹⁰⁵ Twelve days, most of which were associated with multi-day periods of stressed system conditions, accounted for approximately 50% of incremental costs of DA A/S in its first year. See Section 4.2.

¹⁰⁶ Manual commitments for capacity and locational support are included in this analysis. Excluded commitments include manual commitments for auditing, special constraint resources that are requested by transmission owners or distribution companies, and manually-initiated economic commitments.

Figure 9-2: RAA and Manual Capacity and Locational Commitments



Manual and RAA commitments to provide capacity or local reliability support remained rare in both the pre- DA A/S and DA A/S periods. Despite the small number of manual and RAA commitments, there was a decrease when DA A/S was implemented. Since then, manual commitments have occurred in only 11 total hours, adding up to only 2,900 total MWh of committed energy (at EcoMin). About 2,300 MWh of those commitments occurred during two of the twelve highest cost DA A/S days, both in January of 2026. In 2024, there were 7,400 MWh of energy at EcoMin committed either manually (7,000 MWh) or in the RAA process (400 MWh). As a result, while DA A/S appears directionally consistent with fewer out-of-market commitments, the effect is relatively small in the context of prior years' performance.

9.3 Impact on NCPC (Uplift)

This section evaluates the impact of DA A/S on Net Commitment Period Compensation (NCPC) through both direct day-ahead effects and indirect real-time effects. The analysis yields three key takeaways:

- **No clear reduction in day-ahead NCPC from increased revenues:** Higher FER payments did not translate into lower day-ahead uplift, as they were largely offset by lower day-ahead LMPs and ongoing cost recovery needs for marginal units; day-ahead NCPC increased modestly in nominal terms following the implementation of DA A/S.
- **Potential reductions from avoided manual commitments are limited and uncertain:** While DA A/S may reduce NCPC by limiting reliance on RAA commitments, estimated reductions are highly sensitive to assumptions and are bounded at approximately \$35 million annually, with more realistic outcomes likely significantly lower (e.g., roughly \$11 million if limited to peak conditions).
- **Real-time NCPC declined in plausibly affected categories:** Payments associated with out-of-merit actions fell following DA A/S implementation, consistent with improved system preparedness; simple counterfactual estimates suggest roughly \$3 million in real-

time NCPC reductions over the first year, although these results are based on correlations rather than a true counterfactual.

Together, these findings indicate a shift in how system costs are recovered—from out-of-market uplift, as well as Forward Reserve payments, to market-based mechanisms—with total NCPC reductions estimated to be no more than approximately \$38 million in the first year.

Day-Ahead NCPC Impacts

In theory, DA A/S affects day-ahead NCPC through two related channels: increased generator revenue streams and changes in commitment patterns.

First, DA A/S introduces additional compensation through the Forecast Energy Requirement price (FERP) and FRS revenues, which increase total day-ahead revenues to generators. To the extent that compensation under the combined DA LMP, FERP, and FRS revenue exceeds what generators would have earned under DA LMP alone, DA A/S may reduce the need for economic uplift payments.

Second, the FER constraint modifies commitment outcomes in the day-ahead market. When the market clears with insufficient physical supply to meet forecast load, the FER constraint induces additional generator commitments. These commitments can improve system preparedness and reduce the need for manual commitments through the Reserve Adequacy Analysis (RAA) process. In principle, this mechanism can reduce NCPC by shifting compensation from uplift to market-based revenues (DA LMP + FERP).

In practice, observed outcomes do not show an immediate reduction in day-ahead NCPC following the implementation of DA A/S. In the year prior to implementation, day-ahead economic NCPC payments totaled approximately \$4.4 million (0.06% of energy market payments), compared to approximately \$5.4 million (0.07%) in the first year of DA A/S. While this is not a full counterfactual analysis of what DA NCPC would have been absent DA A/S, the nominal increase in NCPC indicates that any moderating effects from enhanced revenue streams were offset by other factors.

Several factors help explain the lack of an immediate decline in day-ahead NCPC. First, generator operating costs were generally higher after DA A/S than before due to higher fuel prices in 2025, pushing up NCPC payments for reasons unrelated to DA A/S. Second, economic NCPC payments are often driven by units that are only marginal for part of their commitment periods. These units require uplift to recover startup costs, no-load costs, and unrecovered costs during non-marginal intervals. While DA A/S changes pricing and commitment decisions, it does not eliminate these cost recovery dynamics.

In addition, DA A/S -induced commitments may increase exposure to uplift in some cases. Incremental commitments driven by the FER constraint tend to involve relatively higher-cost units. If these units do not fully recover their costs through energy and reserve revenues, they may require larger NCPC payments. As a result, DA A/S may simultaneously reduce and increase uplift through different mechanisms, leading to ambiguous net effects on day-ahead NCPC.

Averted RAA Commitments

A second potential source of day-ahead NCPC reductions arises from the avoidance of manual commitments through the RAA process. To evaluate this effect, we identify incremental DA A/S commitments—defined as commitments present in the “DA A/S” simulation that do not occur in a counterfactual “No DA A/S” simulation¹⁰⁷—and estimate their total cost based on startup, no-load, and energy-to-EcoMin costs.¹⁰⁸

To translate these costs into potential NCPC reductions, we assume that all incremental DA A/S commitments would otherwise have been manually committed through the RAA process. Under this assumption, the relevant comparison is between (1) their realized compensation under day-ahead markets and real-time energy revenues, and (2) the uplift that would have been required if these commitments had been made manually.

This approach yields an upper bound on the NCPC reductions attributable to DA A/S. Importantly, the underlying assumption is likely generous. The FER constraint tends to understate expected real-time renewable generation and may therefore induce more commitments than operators would have implemented manually. In addition, historical RAA commitment levels have been low even prior to DA A/S, suggesting that not all incremental commitments would have been necessary in practice.

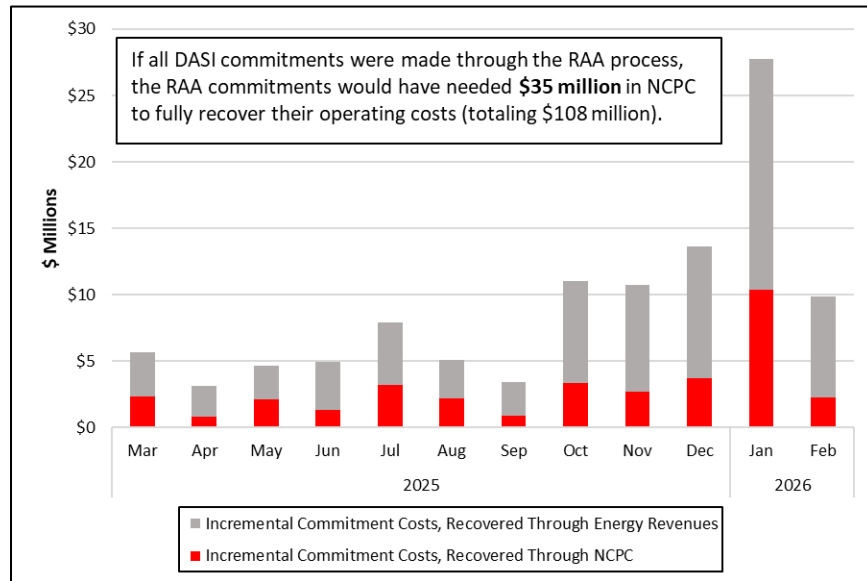
Under this bounding assumption, the total cost of incremental DA A/S commitments was approximately \$108 million in the first year. After accounting for roughly \$72 million in real-time energy revenues, the implied NCPC that would have been incurred under manual commitments is approximately \$35 million. This represents the maximum potential real-time NCPC reductions from avoiding RAA-based commitments.

In Figure 9-3 below, we show the estimated reductions in RAA commitment-driven NCPC. A large share of these estimated reductions is concentrated in a limited number of high-cost days, particularly during Winter 2026 when generator operating costs were elevated. The twelve most expensive DA A/S days account for approximately 30% of total estimated NCPC reductions under this framework. If operators would only have undertaken manual commitments during such high-stress conditions, then the realized NCPC reductions would be substantially lower—on the order of approximately \$11 million.

¹⁰⁷ See Section 4.2 for more information about these simulations.

¹⁰⁸ Note that the DA A/S influence on the commitment mix is not simple – it is not generally true that, for every generator committed under DA A/S, the same generator would have been committed without DA A/S. This analysis identifies the incremental manual commitments that would have been needed without DA A/S to ensure that *at least* the same DA A/S-driven generator mix was online in every hour.

Figure 9-3: Estimated NCPC Cost of Averted RAA Commitments



Taken together, these results suggest that while DA A/S has the potential to reduce NCPC through avoided manual commitments, the magnitude of these reductions is highly sensitive to assumptions about operator behavior. Given historically low levels of RAA commitments, the realized reductions are likely significantly smaller than the upper-bound estimate.

Other Real-Time NCPC Impacts

DA A/S may also affect NCPC outcomes indirectly through changes in real-time system conditions. By increasing day-ahead commitments, DA A/S can improve system preparedness and reduce the likelihood of tight operating conditions that require out-of-market interventions.

The categories of real-time NCPC most likely to be affected include: (1) out-of-merit fast-start commitments, (2) manual dispatches to create “eco surplus,”¹⁰⁹ and (3) real-time manual commitments of long lead-time units. These actions are typically undertaken to maintain sufficient operating reserves or manage system reliability during periods of tight supply-demand balance.

Following DA A/S implementation, NCPC payments and associated out-of-merit generation in these categories declined. Average seasonal NCPC payments across these categories fell from approximately \$3.8 million before DA A/S to \$2.9 million after implementation, corresponding to a 34% reduction. This decline coincided with a reduction in out-of-merit generation, from approximately 42 MW per hour to 33 MW per hour on average.

¹⁰⁹ When system reserves are tight, operators may manually dispatch long lead-time units up in advance of peak load hours to create additional reserve capability; this is referred to as creating “Eco Surplus.” Such out-of-merit dispatches incur significant NCPC credits but are less likely to occur when DA A/S clears such long-lead time units at higher levels in the day-ahead market.

Although these changes are consistent with expected DA A/S outcomes, they reflect correlation rather than causation. Real-time NCPC outcomes depend on a wide range of factors, including load realizations, generator outages, fuel prices, and system conditions more broadly. In the absence of a true real-time counterfactual, it is not possible to attribute these changes solely to DA A/S.

Nevertheless, a simple counterfactual framework can be used to estimate the potential magnitude of real-time impacts. Assuming that out-of-merit generation would have continued at pre- DA A/S levels in the absence of DA A/S, and holding NCPC rates (\$/MWh) constant, estimated NCPC payments for these categories would have been approximately \$14.4 million over the first year, compared to \$11.5 million of actual payments. This implies a roughly \$3.0 million reduction in NCPC attributable to changes in commitment patterns associated with DA A/S.

Summary

Overall, the impact of DA A/S on NCPC payments is mixed and reflects the interaction of several offsetting mechanisms. There is no clear evidence that DA A/S reduced day-ahead NCPC through increased revenue streams alone, as higher FER payments were partially offset by lower day-ahead LMPs and continued cost-recovery needs for marginal units. While DA A/S may not have substantially reduced aggregate NCPC, it changes how costs are recovered by shifting compensation from out-of-market uplift to market-based pricing mechanisms, which represents an important economic benefit of the design.

Notably, other RTOs experienced significant uplift during Winter 2026, while uplift declined in New England during the same period—coinciding with the first winter of DA A/S implementation.¹¹⁰ However, differences in uplift rules, operating conditions, and market structures across regions limit direct comparisons. This analysis suggests that New England could have achieved a similar commitment mix through manual interventions at an estimated annual cost of approximately \$35 million in NCPC (including roughly \$10 million in January 2026). At the same time, given historically low levels of manual commitments and relatively stable system conditions, it is unlikely that New England would have experienced the more extreme uplift outcomes observed in other RTOs even in the absence of DA A/S.

9.4 Revenues Source Mix and Implications

The introduction of the DA A/S market provides explicit compensation for reserve capability, with implications for longer-term resource incentives. While it is too early to observe direct impacts on long-term resource economics (entry, exit, retention), IMM analysis indicates that DA A/S revenues represent a meaningful share of total revenues for fast-start resources, improving the economics of such resources by explicitly rewarding flexibility.

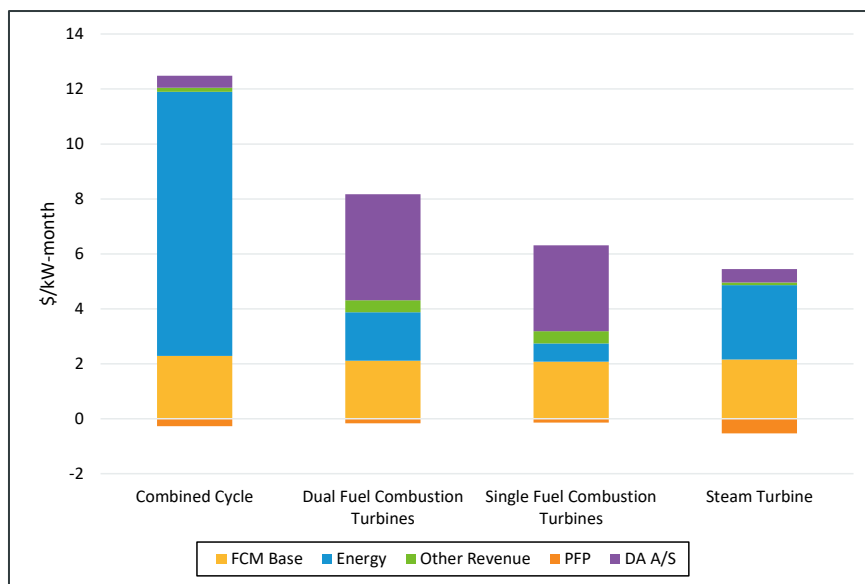
Over time, DA A/S revenues may therefore reduce the “missing money” that some resources seek to recover through the capacity market. As a result, these revenues are expected to influence

¹¹⁰ For example, PJM had over \$750 million in uplift in January 2026 alone. See the PJM markets report for January 2026, available at <https://www.pjm.com/-/media/DotCom/committees-groups/committees/mc/2026/20260219/20260219-item-07a---1-pjm-market-operations-report---presentation.pdf>.

capacity-market offer behavior and, ultimately, capacity-market outcomes. Future estimates of energy and ancillary services revenues should also affect Net CONE estimates and the setting of the capacity market's administrative demand curve. These longer-run effects are not measured in our first-year incremental-cost estimates but are important to understanding the design's broader economic implications.

Figure 9-4 below shows the net revenue for different technology types categorized by the following revenue sources: base capacity from the Forward Capacity Market, PFP, energy, DA A/S, and other revenue.

Figure 9-4: Net Revenue by Technology Type



DA A/S did not contribute significantly to combined-cycle profitability given that they primarily earn revenues by providing energy rather than reserves. Steam turbines also did not have significant DA A/S revenue because they are non-fast-start and cannot provide reserves from an offline state. Combustion turbines received about half of their revenues from DA A/S during the year (combined, \$3.53/kW-mo of a total of \$7.19/kW-mo). DA A/S payments exceed revenues from the now defunct Forward Reserve Market, which averaged about \$1.30/kW-month in 2023 and 2024.

Section 10

Reliability Outcomes

The evaluation of reliability outcomes during the first year of DA A/S is based on a structured set of metrics designed to assess whether the design has led to improved system preparedness and performance. Because reliability outcomes are influenced by system conditions, fuel and energy prices, and a broad range of market-based incentives (e.g., energy prices, Pay-for-Performance), it is difficult to assign causality to DA A/S incentives. This analysis focuses on behavioral and operational indicators that are consistent with the design objectives, including resource availability, day-ahead plan flexibility, and gas scheduling. These indicators are designed to provide a framework for evaluating reliability value over time.

Key Takeaways

Although it is difficult to assign causality to DA A/S given the broad range of market incentives at play over the first year, certain reliability-based metrics for DA A/S resources appear promising.

Additional revenue sources to combustion turbines providing day-ahead reserve products has coincided with improvements to availability. Additionally, more fast-starts are allocated DA A/S obligations, rather than energy, resulting in a day-ahead schedule that has more longer-lead-time units, and fast-start units ready to respond to unexpected events.

Finally, we did not observe any strong gas scheduling behavioral response to DA A/S incentives, although the majority of participants who responded to our survey indicated that DA A/S has influenced their fuel procurement decisions across several fuel types.

10.1 Commitment Differences

The commitment and dispatch outcomes in the day-ahead market may not always reflect expected physical real-time conditions. For example, load-serving entities may clear less demand than the ISO's load forecast, resulting in less physical energy supply clearing in the day-ahead market than is expected to be needed in real time. When this happens, there is a day-ahead "energy gap," which we define here as (1) the expected real-time load less (2) the amount of day-ahead energy awards on physical resources (i.e., excluding virtual supply).¹¹¹

A key design change under DA A/S was the explicit incorporation of the ISO's load forecast into the day ahead market clearing process. The Forecast Energy Requirement (FER) constraint ensures that sufficient physical capability is procured in the day ahead market to meet forecasted load. This requirement may be satisfied through day-ahead energy awards from physical supply resources as

¹¹¹ Under this definition, a negative "energy gap" value indicates that the quantity of cleared physical energy *exceeded* the load forecast.

well as awards of Energy Imbalance Reserve (EIR). Consequently, “the energy gap is closed by procurement of additional energy and EIR.

Day-Ahead Energy Gap

Our evaluation indicates that DA A/S has likely decreased the energy gap, especially at the tail end of the distribution (i.e., DA A/S appears to reduce the incidence of extreme energy gaps). The following table shows energy gap statistics comparing pre-DA A/S times (March 1, 2023-February 28, 2025) with Post-DA A/S implementation (March 1, 2025-February 28, 2026).

Table 10-1: Energy gap statistics pre- and post-DA A/S implementation, in MW

Time Period	Mean	75th Percentile	90th Percentile	95th Percentile	99th Percentile
DA A/S	(94)	198	395	540	800
Pre-DA A/S	(132)	234	542	721	1,079
Difference	38	(36)	(147)	(181)	(278)

Consistent with expectations, DA A/S has reduced the frequency of extreme energy gaps. Pre-DA A/S, the 90th percentile was about 540 MW – a level corresponding to the 95th percentile post-DA A/S implementation. This outcome is expected because the FER constraint enforces a physical supply constraint that ensures physical supply cleared plus EIR in the day-ahead market is adequate to deliver forecasted real-time energy. The enforcement of the additional constraint results in lower energy gaps since DA A/S was implemented.

Fast-Start Commitment in the Day-Ahead Energy Mix

We find that fast-start units made up a smaller portion of the day-ahead generation mix, in favor of longer-lead-time generators, since DA A/S was implemented. The shift indicates that fast-start units are being held for reserves more often after DA A/S implementation, an outcome that is also evident in our simulation studies.¹¹² The following table shows the percentage of day-ahead cleared MWs for energy by startup + notification time, comparing pre- DA A/S times (March 1, 2023-February 28, 2025) with post- DA A/S implementation (March 1, 2025-February 28, 2026).

¹¹² Fixed generation mix is estimated using the percentage of the total Economic Minimums of units committed in the day-ahead market. Calculations using Economic Maximum were similar.

Table 10-2: Day-Ahead Generation by Startup plus Notification Time

Startup plus Notification Time	All Hours			Top 3% Load Hours			Top 12 Days
	Pre- DA A/S	DA A/S	Delta (% Points)	Pre- DA A/S	DA A/S	Delta (% Points)	
Less Than 30 Minutes	30%	19%	-11	25%	18%	-7	16%
Between 30 Minutes and 1 Hour	2%	1%	-1	2%	2%	0	1%
Between 1 and 2 Hours	1%	1%	0	1%	1%	0	1%
Between 2 and 4 Hours	0%	0%	0	0%	0%	0	0%
Between 4 and 8 Hours	44%	52%	8	46%	49%	4	51%
Between 8 and 16 Hours	10%	12%	1	16%	19%	3	19%
Longer than 16 Hours	12%	15%	3	10%	11%	0	12%

Since DA A/S was implemented, the percentage of fixed (i.e., up-to EcoMin) generation from fast-start units has decreased by about 11 percentage points across all hours as some generators now clear DA A/S awards. The fast-start fixed MWs have been offset by longer-lead time generation, with startup + notification time greater than 4 hours. In the highest load hours, as well as the twelve days with the highest DA A/S costs, fast-start generation makes up a smaller percentage of fixed generation, with the longer-lead time generation increasing, when compared with all hours. This indicates that, post- DA A/S, the day-ahead schedule may be more flexible, with more flexible units held in reserve to help respond to unexpected real-time events.

Long Lead-Time Commitment Differences in Simulated Outcomes

Simulated day-ahead market clearing results without DA A/S constraints can directly show the impacts of DA A/S on the day-ahead supply mix. In particular, this can be used to show how DA A/S increased the commitment and dispatch of long-lead time units in the day-ahead market to create reserve availability. Table 10-2 below shows the commitment of economic, long-lead-time units between DA A/S outcomes and simulated non-DA A/S counterfactuals.^{113,114}

Table 10-3: Economic Long Lead-Time Commitments With and Without DA A/S

Time	Average Long Lead-Time Generator MWh		
	Non-DA A/S	DA A/S	Difference
All Hours	5,283	5,359	+ 76 (1%)
Top 12 Days	6,766	6,865	+ 99 (1%)

¹¹³ For this table, we define long lead time units as any generator that offered a combined startup and notification time greater than 4 hours. We include only economic generation, excluding self-schedules or other must-run generation.

¹¹⁴ While the table uses the terms “Non-DA A/S” and “DA A/S” to denote scenarios, note that the “DA A/S” scenario does not reflect the actual DA A/S outcomes, but rather reflects the benchmark scenario in our simulation software. Using this scenario as a comparison rules out any outcomes that are driven by differences in market clearing software. However, note that the DA A/S benchmark scenario performs well and accurately reflects true DA A/S outcomes.

DA A/S increased the amount of long lead-time generation that cleared the day-ahead market, with an average increase of 76 MW (1%) relative to day-ahead market results without DA A/S constraints. Notably, while this table shows *all* cleared long lead-time energy, this result holds even when considering only *commitment* energy up to generators' economic minimum limits. Therefore, DA A/S materially increased committed long lead-time generation ahead of real-time operating conditions.

The impacts of DA A/S on the commitment and dispatch of long lead-time generation were relatively high on the Top 12 days. On average across these days, DA A/S resulted in a 99 MW increase in economic long lead-time generation that cleared the day-ahead market.

10.2 Fuel Scheduling and Management

The DA A/S market strengthens preparedness incentives in the period between day-ahead clearing and real-time operations with an expectation that resource owners are more likely to ensure fuel is available when needed to cover their DA A/S obligation. For gas-fired resources, DA A/S positions can increase the value of securing fuel in advance.¹¹⁵

This analysis focuses on:

- gas nominations pre- and post-DA A/S implementation,
- the share of gas nominated day-ahead, and
- energy preservation for batteries and pump storage units.

The empirical results suggest that, at a system level, resources have not altered their approach to securing fuel based on DA A/S positions. The following table shows scheduled gas generation, estimated expected gas consumption associated with the day-ahead cleared energy offer, and DA A/S positions, across all seasons, and in the top 12 days with the highest DA A/S costs.¹¹⁶

¹¹⁵ Specifically, a resource has an incentive to procure fuel in advance when the expected reduction in closeout exposure exceeds the incremental cost of arranging fuel, including the risk that the gas is not needed and must be resold or otherwise managed.

¹¹⁶ Gas required to deliver day-ahead energy awards is estimated using generator input-output curves and startup gas estimates associated with the day-ahead schedules. Scheduled gas represents timely and evening gas nomination estimates from an external vendor. Both the estimated gas required to deliver day-ahead energy and the hourly scheduled gas are estimates based on the best available data.

Table 10-4: Gas scheduling pre- and post-DA A/S implementation

Time Period	DA A/S Status	Hourly Day-Ahead Cleared Gas Generation (MW/hour)	Hourly DA A/S Position (MW/hour)	Hourly Estimate Gas Required to Deliver Day-Ahead Energy (MMBtu)	Hourly Scheduled Gas (MMBtu)	(Scheduled Gas) / Gas Required to Deliver Day-Ahead Energy
Spring	Pre-DA A/S	5,324		39,852	43,274	109%
	DA A/S	5,416	834	40,649	43,868	108%
Summer	Pre-DA A/S	8,258		62,363	62,296	100%
	DA A/S	8,741	989	65,949	67,799	103%
Fall	Pre-DA A/S	6,968		52,399	53,251	102%
	DA A/S	7,139	1,052	53,384	49,954	94%
Winter	Pre-DA A/S	5,474		40,617	40,308	99%
	DA A/S	6,993	788	50,867	48,056	94%
All Seasons	Pre-DA A/S	6,510		48,831	49,806	102%
	DA A/S	7,072	916	52,720	52,443	99%
Top 12 Days		8,611	1,117	64,903	66,115	102%

In the two years before DA A/S, gas generators scheduled 2% more gas than estimated gas consumption of their day-ahead schedules (All Seasons, Pre-DA A/S, rightmost column). This number declined slightly, to 99% of estimated gas in the first year of DA A/S despite DA A/S positions that amounted to about 13% of day-ahead energy positions. Summer was the only season in which gas generator scheduled more per MMBtu of estimated day-ahead gas consumption after DA A/S implementation than in pre-DA A/S periods.

In the top 12 days, gas generators scheduled 2% more fuel than was necessary to cover their day-ahead energy position. DA A/S did not necessarily cause the subtle shifts in gas scheduling we observed; it is likely that changes in gas costs, OFOs, gas constraints and overall increases in demand in all of the seasons led to the shift. However, we did not find strong evidence that gas generators scheduled additional gas to cover their DA A/S positions, with similar amounts of scheduled gas per day-ahead cleared generation MW pre- and post-DA A/S implementation.

As a counter point to the above empirical analysis, we note that in response to our survey, six out of 16 respondents with gas generators in their portfolios indicated that they procured fuel in response to a DA A/S positions.

For **stored-fuel resources**, including batteries and pumped storage resources, the design may impact both generation timing and fuel preservation incentives. Resources may be incentivized to defer generation in earlier hours to maintain flexibility for periods when DA A/S-related obligations introduce risk of fuel-related outages. During its first year, the impact of DA A/S on overall storage generation profiles appears small given that about 89% of storage generation is produced by assets that do not have a DA A/S obligation during the day and another 5% is produced on days in which

the DA A/S obligation occurs earlier in the day (so generators are available to cover if needed without altering their optimal schedule).

Despite these data limitations, the average storage generator without a DA A/S obligation ran more often during the morning ramp in hours ending 7-9 (13% of generation) than those with a late-day DA A/S obligation (3%).¹¹⁷ On the twelve highest-cost DA A/S days, the difference was more pronounced; storage generators with late-day DA A/S obligations produced zero MWs in hours ending 7-9, compared with 8% of generation for resources without a DA A/S obligation.

10.3 Resource Availability and Performance

Our evaluation of resource availability and performance focuses on outages rates across different technology types. The following table shows the total percentage of seasonal claimed capability out-of-service. The outages include planned and forced outages. The column on the far right shows estimated capacity out of service due to oil or gas availability during the Top 12 days with the highest incremental cost from DA A/S.¹¹⁸

Table 10-5: Total Percentage of Accredited Capacity Out-of-Service

Technology	Pre-DA A/S	DA A/S	Difference (% Points)	Top 12 Days	Top 12 Days – Due to Fuel Availability
Steam Turbines	21%	25%	4	20%	0%
Combustion Turbines	18%	11%	-7	11%	3%
Combined Cycles	12%	14%	2	9%	2%
Total: Above Technology Types	14%	15%	1	11%	2%

The combined outage rates of steam turbines, combustion turbines, and combined cycles across all hours was similar pre- and post-DA A/S, from 14% of claimed capability to 15% of claimed capability.

Outage rates decreased substantially for combustion turbines (an average of 18% of capacity out-of-service vs. 11% post DA A/S implementation). While it is difficult to isolate the incremental effect of DA A/S from other market incentives, it is likely that DA A/S revenues played a part in the reduction for combustion turbines, which receive over half of their net revenue from DA A/S between (discussed in the next section). The availability incentives could also have been influenced by higher energy prices; however, energy price incentives are shared by combined cycles and steam turbines, which did not see an increase in availability.

The design provides incentives for timely return to service by providing a revenue stream for units that are less often called upon for energy but are willing to provide reserves. Despite the additional incentives to procure fuel, about 3% of combustion turbine capacity was out of service during the

¹¹⁷ Late day in this context is a generator that has a DA A/S obligation in hour ending 17 or later.

¹¹⁸ The IMM estimated out of service MWs using outage data reported to the ISO. The values represent estimates due to the nature of the data.

12 highest cost DA A/S days due to depleted oil inventories, and 2% of combined cycle capacity was unavailable due to gas availability. Due to the energy dynamics in this especially-tight winter it is not possible for us to conclude at this time that DA A/S improved fuel procurement or fuel retention.

While the reduction in combustion turbine outage rates is directionally consistent with DA A/S incentives and revenues, the evidence is insufficient to attribute causality. One hypothesis is that higher DA A/S revenues may have led some fast-start resources to defer maintenance, improving short-run availability. Continued monitoring is needed to distinguish such maintenance timing effects from other drivers, e.g., weather, dispatch patterns, etc.

Section 11

Survey Results

The IMM conducted an online survey of market participants in February 2026 to better understand how the market reforms under DA A/S were being experienced by participants firsthand. The survey covered topics including participant understanding of the market, offer behavior, risk perceptions, and views on market performance. In total, 42 respondents completed the survey, yielding a 36% response rate. Of those, 76% indicated they were active in the DA A/S market. The survey therefore includes the perceptions of some participants not offering into the DA A/S market but primarily reflects the experience of those actively engaged in the market.

Key Takeaways

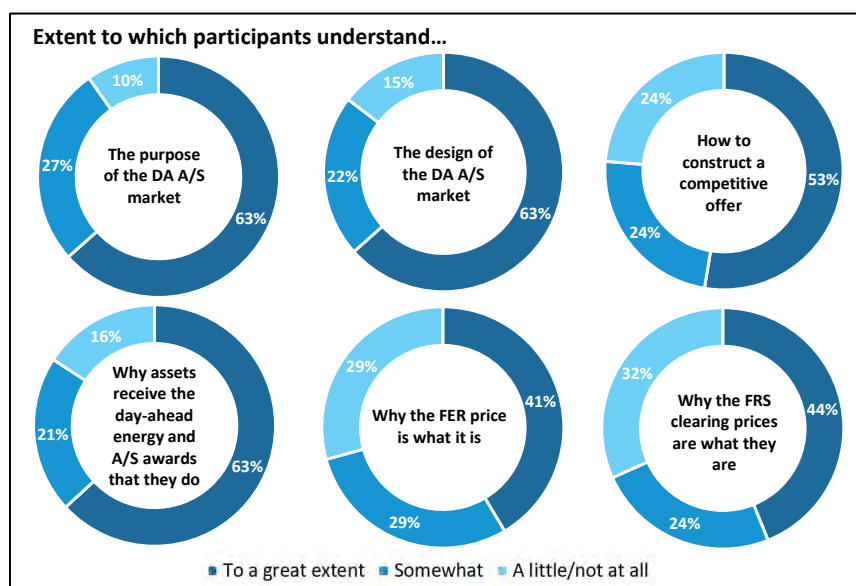
The survey results suggest that many participants are responding to the incentives embedded in the design, particularly with respect to fuel procurement and operational readiness. However, market complexity and uncertainty continue to influence behavior. Some participants have adjusted their offer behavior over time as they've become more familiar with the market, but many indicated that they want additional training to enhance their understanding and comfort with specific market features. These findings are consistent with the broader analysis in this report, which shows that risk, uncertainty, and market design features play a significant role in shaping offer behavior and market outcomes.

Below, we provide a high-level summary of the survey results.

Market Understanding

Participants generally understand the purpose and high-level design of the DA A/S market but have less confidence in constructing offers and understanding clearing prices, as shown in Figure 11-1.

Figure 11-1: Participant Understanding of the Market (Survey)



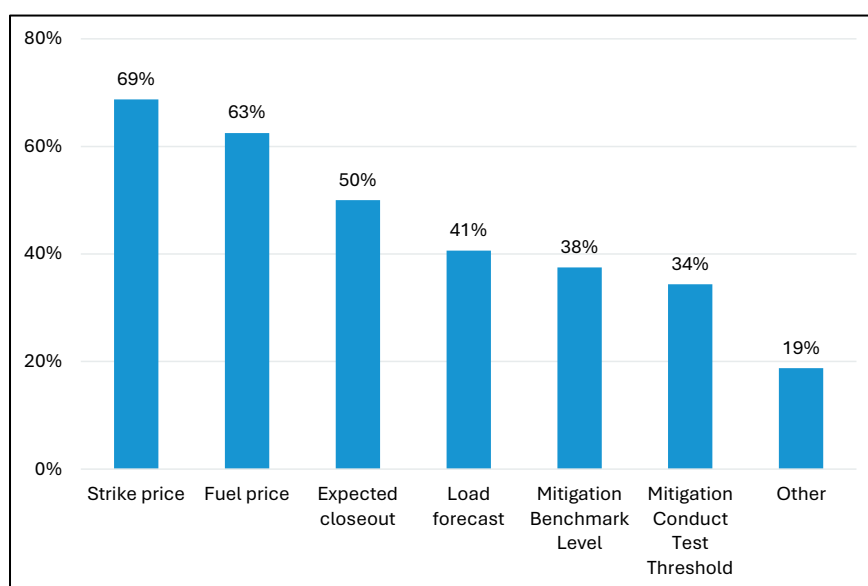
Approximately two-thirds of respondents reported a strong understanding of the market’s purpose and design. However, only about 41–44% reported a strong understanding of FRS and FER price formation, and just over half reported confidence in their ability to construct competitive offers. About 16% reported no confidence in constructing offers. These results suggest that while the design is understood conceptually, translating that understanding into effective participation remains challenging. Additionally, over two thirds of respondents indicated that additional training, particularly on offer formulation, would be beneficial.

Market Participation and Offer Behavior

Some participants indicated that they have changed the frequency or quantity of their offers over time, citing changes in commercial strategy, improved understanding of the market, and changes in fuel prices and asset availability as the main reasons for varying offer behavior.

Participants who do participate in the DA A/S market generally incorporate multiple inputs into their offers, including strike prices, fuel costs, and expected close-outs, as shown in Figure 11-2.

Figure 11-2: Inputs to DA A/S Offers (Survey)



Note: Sample size = 32. Excludes “prefer not to respond” and “not applicable” responses.

A notable share of respondents (31%) reported that they do not explicitly incorporate strike prices in their offers, relying instead on fuel prices, expected closeouts, and/or load forecasts. At the same time, multiple respondents cited uncertainty related to strike prices, expected close-outs, and real-time exposure. These concerns are consistent with the broader finding that risk and uncertainty contribute to higher offer prices and variability in offer strategies.

Operational Impact

Survey results also indicate that DA A/S awards influence operational decisions. Approximately 71% of respondents reported taking actions in response to awards, most commonly procuring fuel.

Risk Perceptions

Participants were evenly split in their ability to account for risk in offers. One-third agree to a great/very great extent that they can sufficiently account for risk, one-third agree to some extent, and one-third agree a little or not at all. Despite this, approximately 75 percent indicated that DA A/S revenues generally cover the costs of providing reserves.

Mitigation and Benchmarking

Participants are generally aware of the mitigation design and many engage with the IMM to revise their benchmark levels. Most respondents who have revised their benchmark level with the IMM agree that the new level accurately reflects costs. However, some highlighted the administrative burden of frequently updating their benchmark level. These results underscore the importance of maintaining a mitigation framework that is both effective and operationally workable.

Perceived Benefits and Challenges

Participants most frequently cited increased revenue and improved compensation for reserve capability as key benefits of the DA A/S market. Other benefits include improved fuel planning and more transparent reserve pricing.

The most commonly cited challenges include:

- market complexity and difficulty forecasting outcomes,
- uncertainty in strike prices and closeout charges, particularly during stressed periods,
- challenges in constructing offers and managing risk, and
- administrative burden associated with mitigation.