

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

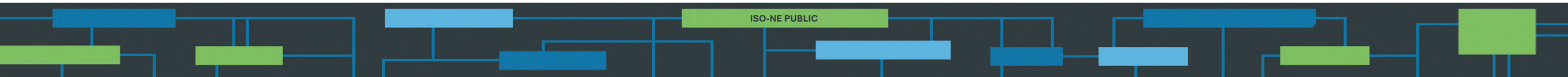
MANAGER, BUDGET & FINANCE REPORTING



Continuation of Section IV Rates Absent FERC Order

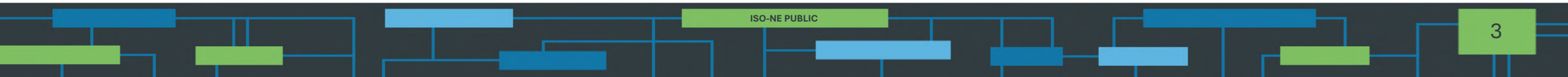
Proposed Effective Date: October 1, 2026

- 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



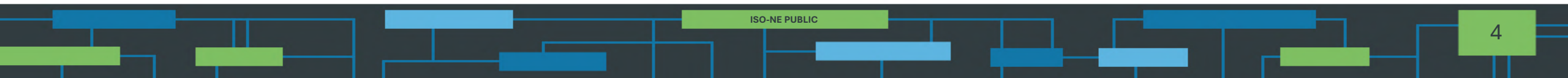
Background

- 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.



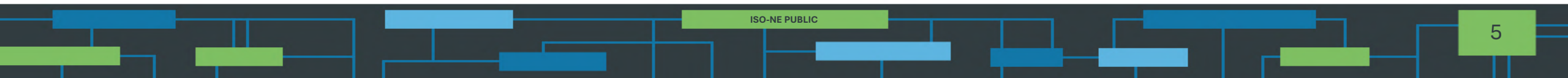
Rationale for Change

- 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



Proposal

- The ISO proposes changes to ISO Tariff Sections IV.A and IV.B to add language that permits the ISO to continue operations using existing rates and budgets until a FERC order is received
 - Section IV.A changes add language on potential adjustment/true-up of billing amounts should the ISO need to continue billing, temporarily, under prior year rates
 - Would only be necessary if FERC approval is not received before the first monthly settlement billing is in progress, which is approximately mid-February of the budget year
 - Also includes Schedule 5 NESCOE rates
 - NESCOE's annual budget and Schedule 5 rate is made via a separate FERC filing; however, the filing timeline and FERC approval of NESCOE's annual budget has largely been consistent with those of the ISO
 - Section IV.B changes provide that the ISO may continue capital spending based on an amount no greater than the prior year's annual capital budget or the pending capital budget (whichever is less)
 - The ISO would then adjust capital budget spending or priorities, if necessary, based on the final FERC order and include any necessary adjustments as part of the next quarterly capital budget filing



Summary of Proposed Tariff or Manual Changes^[1]

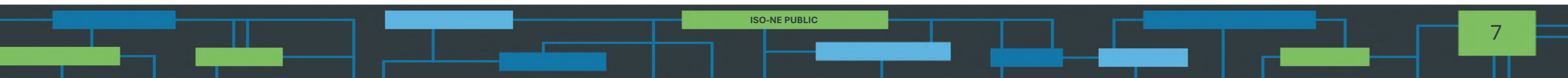
Section	Tariff or Manual Change	Reason for Change
New Paragraph: Section IV.A.2.2(4) “Procedures if Rates are not approved by January 1”	“In the event that the Commission has not issued an order regarding the calendar year rates and charges for each Service contained in Schedules 1, 2, 3 or 5 of Section 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

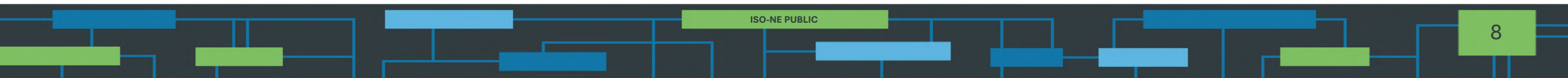
Section	Tariff or Manual Change	Reason for Change
Edit to Section IV.B.2 “Purpose of and Charges Assessed Under Section IV.B”	In the first paragraph of this section edit the word “owned” by removing the letter “n” to make the word “owed”	Grammatical edit to convey the correct meaning of the word and 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

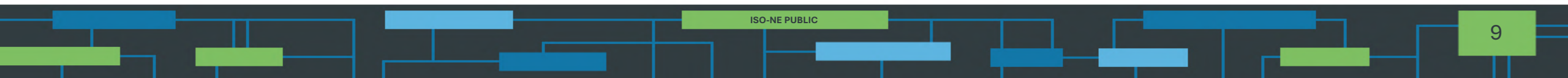


Stakeholder Schedule

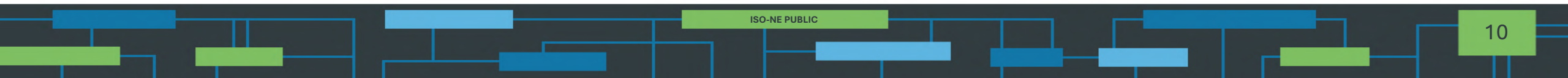
Stakeholder Committee and Date	Scheduled Project Milestone
Budget and Finance Subcommittee April 17, 2026 ^[3]	Introduce Section IV.A and IV.B proposed changes for discussion and answer any clarifying questions
Participants Committee May 7, 2026	Vote on Section IV.A and IV.B changes

^[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



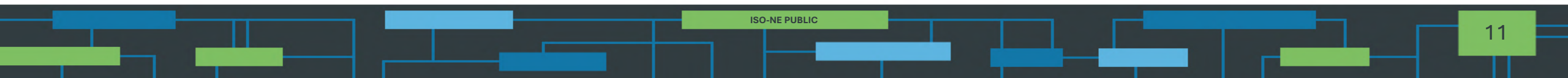
About the Presenter

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ISO New England

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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

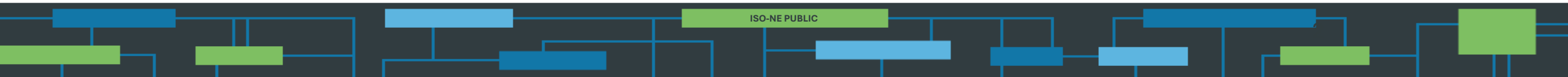


Pay for Performance Revisions: Treatment of External Transactions

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

Proposed Effective Date: October 1, 2026

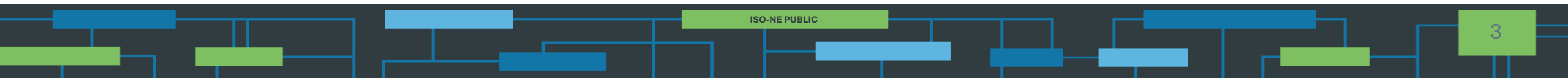
- The External Market Monitor (EMM) and the Internal Market Monitor (IMM) have highlighted a possible improvement to the efficiency of the Forward Capacity Market in its treatment of external transactions. Stakeholders have also expressed interest in this topic
- ISO-NE proposes changes to the Pay-for-Performance (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

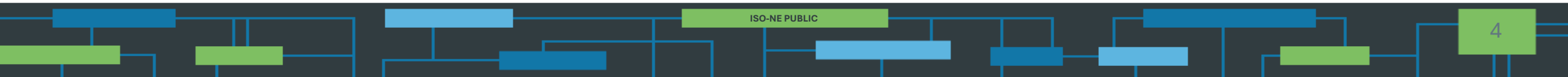
- There are two types of External Transaction Sales (Exports) that are relevant to this project
 1. Exports that are associated with the energy and reserves that a generator provides to the ISO-NE system, submitted in accordance with III.1.10.7(f)
 2. Exports that are **not** associated with a specific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

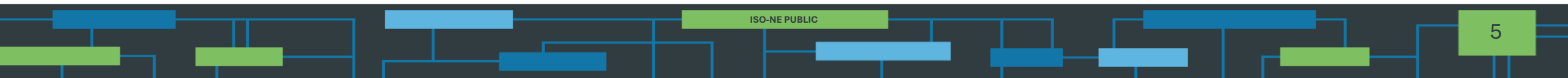
- Under current rules: Exports reduce the Actual Capacity Provided (ACP) of two kinds of resources, *but not below 0*
 - For generator capacity Resources associated with an export: $ACP = \text{Energy} + \text{Reserves} - \text{Exports}$
 - This reduction of ACP is provided in Ill.13.7.2.2(a), last sentence
 - 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

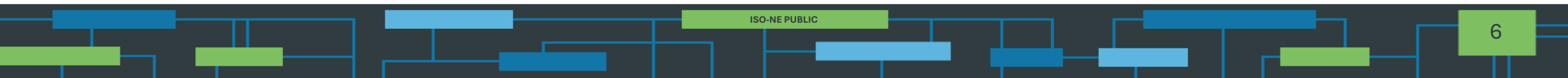
- There is an opportunity for increased efficiency by removing a method in which market participants could receive PFP credits without contributing to system reliability
- For example, during a CSC, assume:
 - Participant A has 0 CSO, schedules 0MWh of imports, 1MWh of exports, and *does not* receive 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

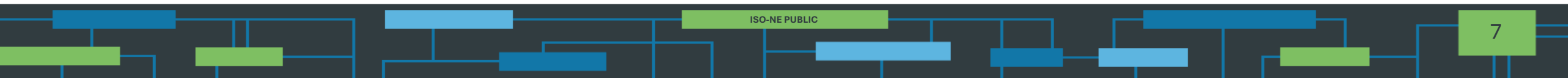
- To resolve the market inefficiency, the ISO proposes to *charge system-backed exports the PPR during a Capacity Scarcity Condition*
 - *System-backed exports*: Exports that are either 1) associated with a generator, but exceed the generator's energy and reserves provided, or 2) not associated with 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

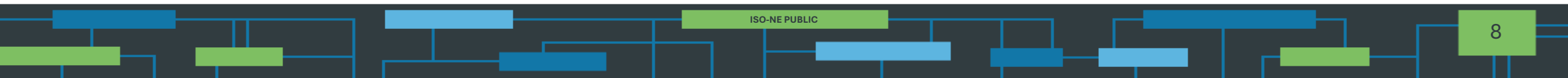
- Generator-backed exports reduce the generator's Actual Capacity Provided, and thus reduce the PFP credits or increase the PFP charges of that generator
- In this case, the combination of the generator and its associated exports is neither alleviating nor worsening the CSC
 - Note that if an export 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 $\text{load} = \text{Total Actual Capacity Provided} - \text{Designated Reserves}$
- 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

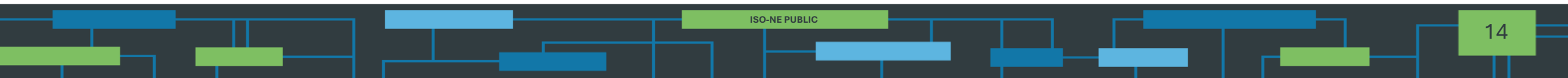
Conclusion

- 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

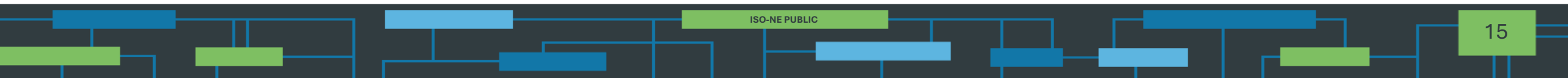
Stakeholder Committee and Date	Scheduled Project Milestone
Markets Committee March 10-12, 2026	Summary of opportunity for improvement-and proposed design
Markets Committee April 14-16, 2026	Additional details on design and initial review of proposed Tariff language and any stakeholder amendments
Markets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

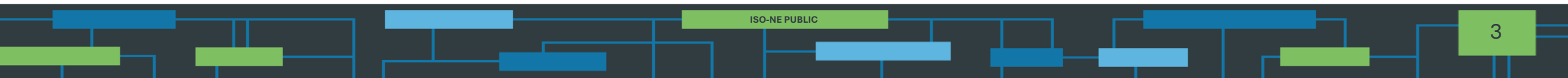
Proposed Effective Date: October 1, 2026

- 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

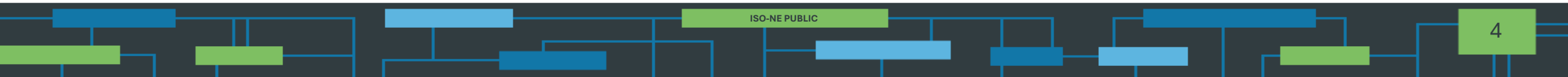
Overview of Proposed Solution

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

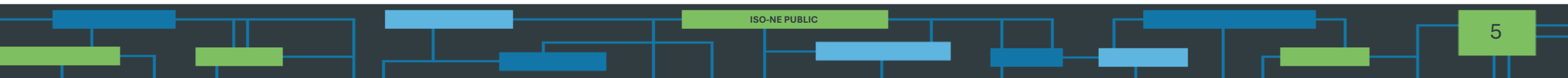


FOLLOW-UPS FROM MARCH MARKETS COMMITTEE



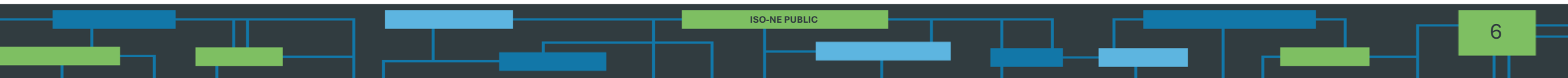
Follow-ups from March MC

- **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



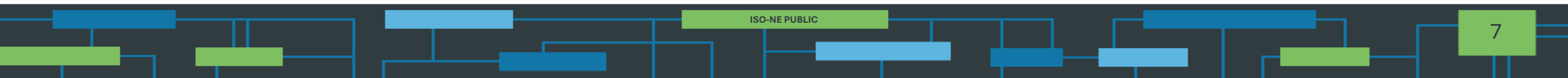
Follow-ups from March MC

- **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

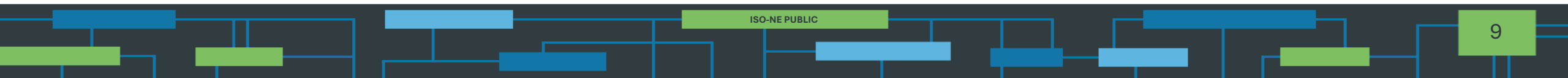
NEPOOL PARTICIPANTS COMMITTEE
JUNE 16-18, 2026 SUMMER MEETING, AGENDA ITEM #7
Attachment F

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

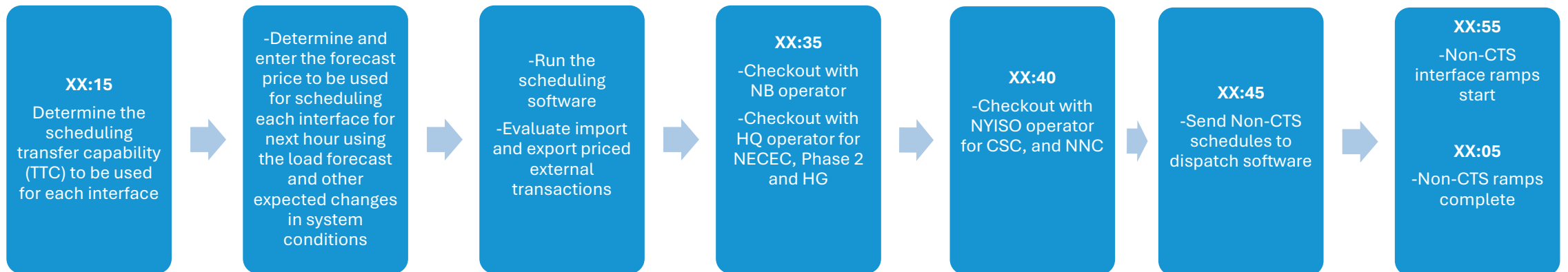
EXTERNAL TRANSACTIONS SCHEDULING PROCESS

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

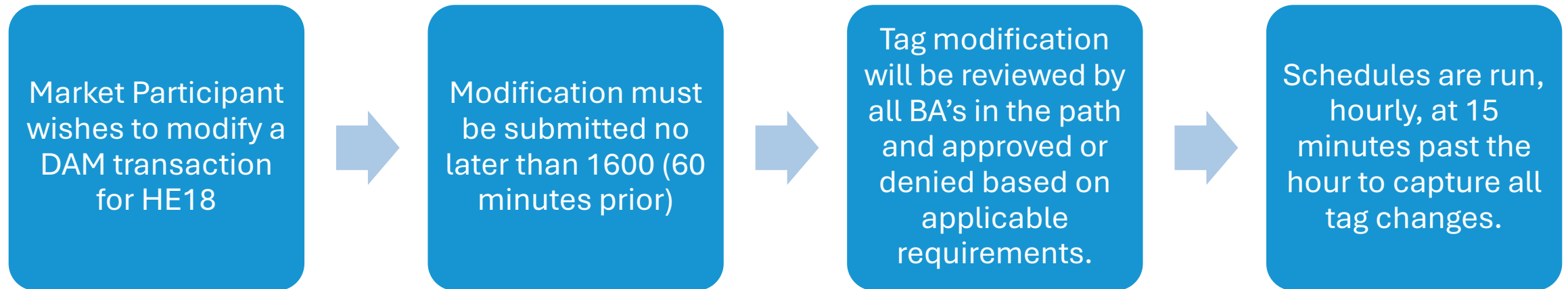
XX:10, XX:25, XX:40, XX:55

- CTS Schedules begin ramping

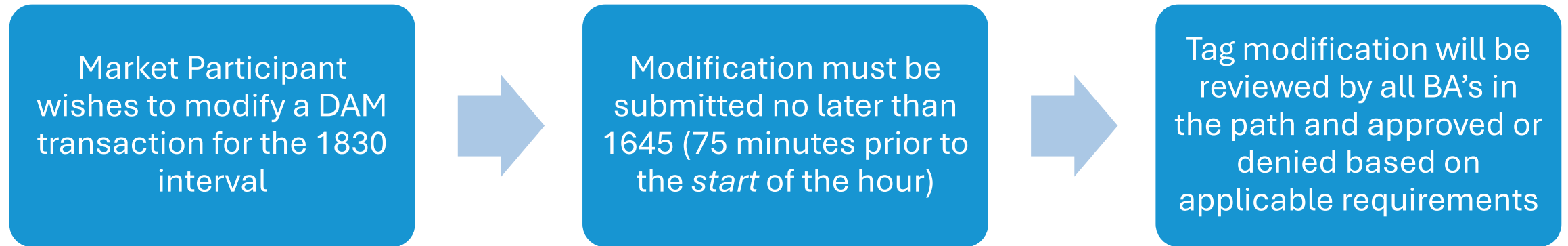
XX:05, XX:20, XX:35, XX:50
CTS schedule ramp complete

* 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

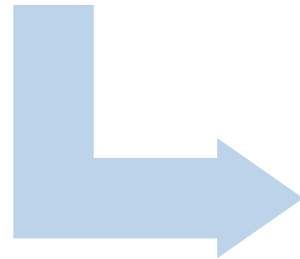
• CTS Interface

RT Only Exports will be curtailed to zero as needed

• Non-CTS

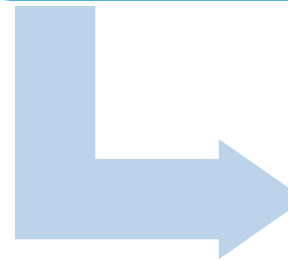
OP-4 Curtailments

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

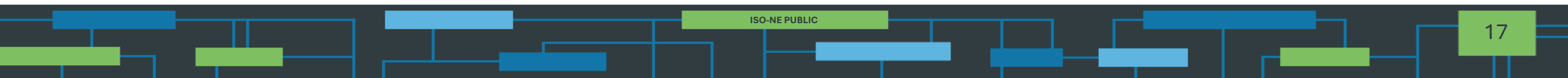
Can a participant adjust an external transaction that had been scheduled on the day-ahead market, within some lead time of the scheduled period?

- 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

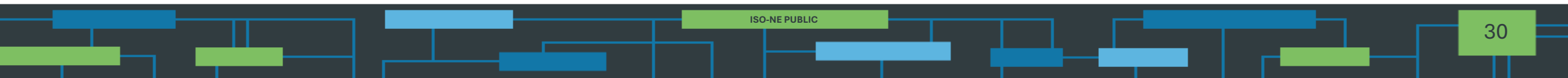
Stakeholder Committee and Date	Scheduled Project Milestone
Markets Committee March 10-12, 2026	<i>Summary of market inefficiency and proposed design</i>
Markets Committee April 14-15, 2026	Additional details on design and initial review of proposed Tariff language
Budget and Finance Subcommittee April 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

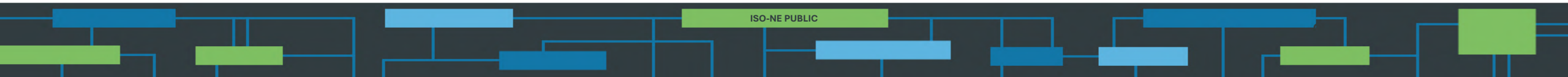


Pay-For-Performance: Financial Assurance Changes for External Transactions and Balancing Ratio

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

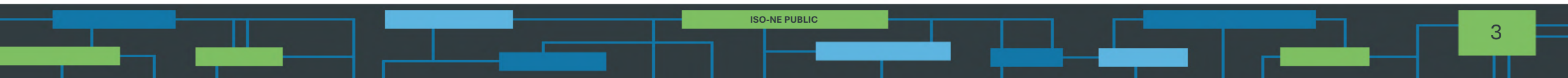
Proposed Effective Date: October 1, 2026

- 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



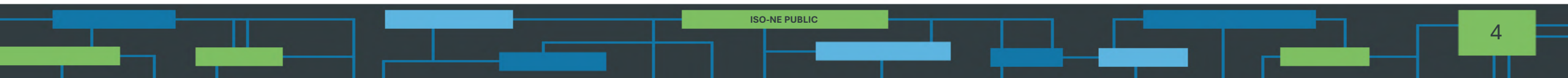
EXTERNAL TRANSACTIONS

FAP Revisions



Background

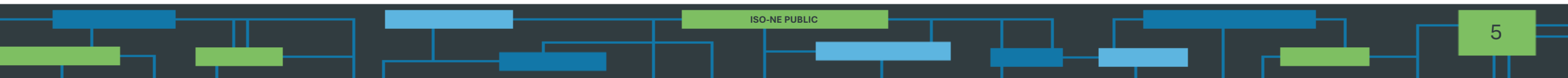
- During the April 17th BFS meeting, the ISO proposed updating the FAP to include a new financial assurance requirement
- **SBE FA = PPR * SBE MW * Scarcity Hours**
 - PPR = Performance Payment Rate
 - SBE MW = The Market Participant's Average SBE MWs across all CSCs occurring within the relevant group 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

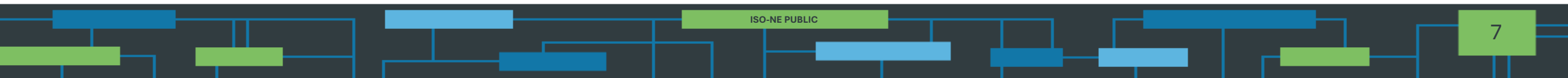


Example: SBE FA Calculation

- **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
 - **$\$3,500 \text{ PPR} * 80 \text{ SBE MW} * 2 \text{ Scarcity Hours} = \$560,000$**

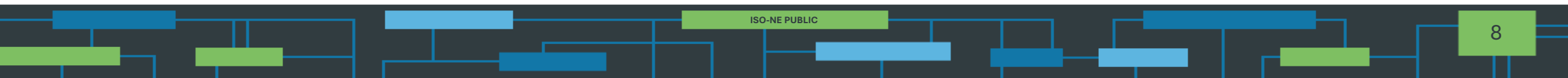
Impact of Proposal

- 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



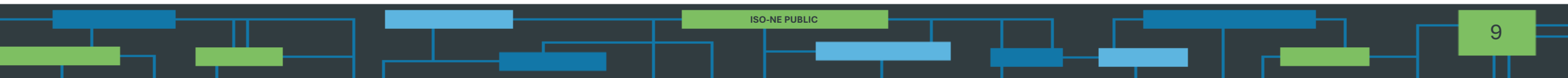
BALANCING RATIO

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

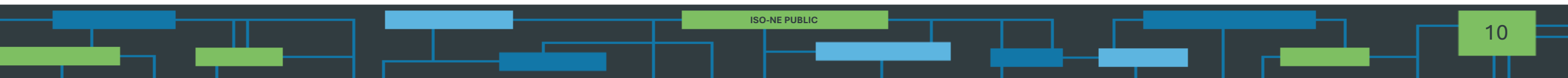


Example: ABR Calculation

- 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

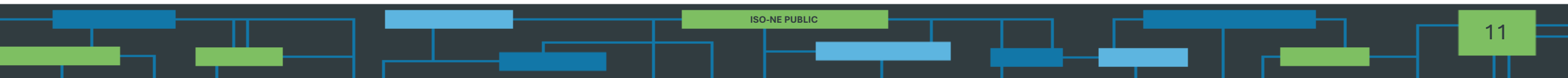
CSC Event Date	Season	Number of CSC Intervals	Original BR	Recalculated BR (SBE's removed and cap of 1.0)
Jun 2024	Summer	6 (0.5 hours)	0.869	0.847
Aug 2024	Summer	22 (1.833 hours)	0.903	0.883
Jun 2025	Summer	37 (3.083 hours)	1.031	0.999
Nov 2025	Shoulder	6 (0.5 hours)	0.696	0.634

- 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

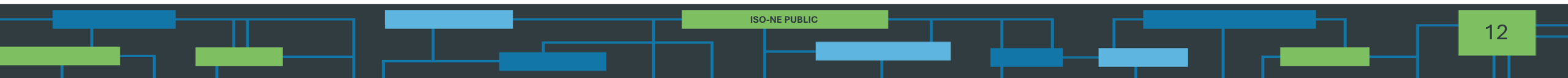
A Designated FCM Participant with System-Backed Export transactions, as defined in Section III.13.7.2.A and Section III.15.8.2.A of Market Rule 1, must include SBE Financial Assurance in the calculation of its FCM Financial Assurance Requirements under the ISO New England Financial Assurance Policy.

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

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

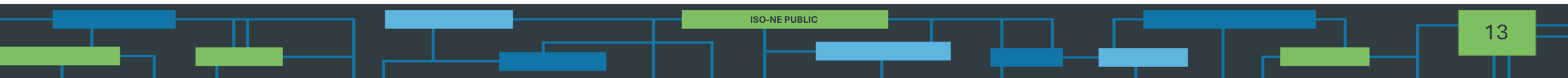
Where:

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.

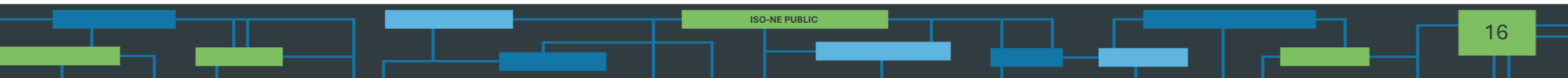
FAP Redlines: ABR

- 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.

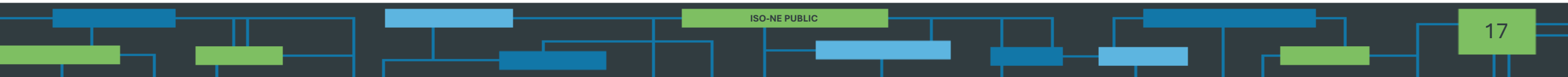
FAP Redlines: Administrative Changes

- 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

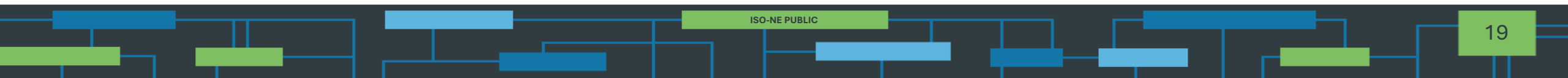
- The ISO is proposing FAP changes to mitigate the risk of a market participant defaulting on SBE charges incurred during CSCs
- The ISO is also proposing to change the FAP definition of ABR to include the 1.0 BR cap and utilize recalculated historical BR values based on the newly proposed BR formula
- 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

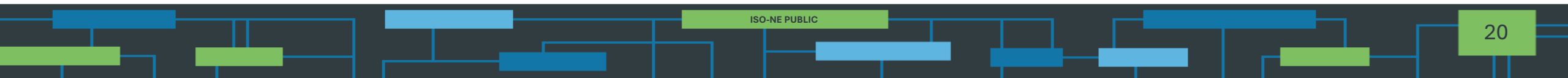
Stakeholder Committee and Date	Scheduled Project Milestone
Budget and Finance Subcommittee April 17, 2026	Introduce proposed Financial Assurance revisions for treatment of external transactions and Balancing Ratio cap under Pay-for-Performance
Budget and Finance Subcommittee May 8, 2026	Present associated 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



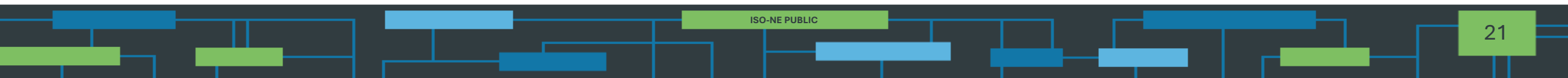
About the Presenter

Zach Shell

Supervisor, Market and Credit Risk

ISO New England

zshell@iso-ne.com



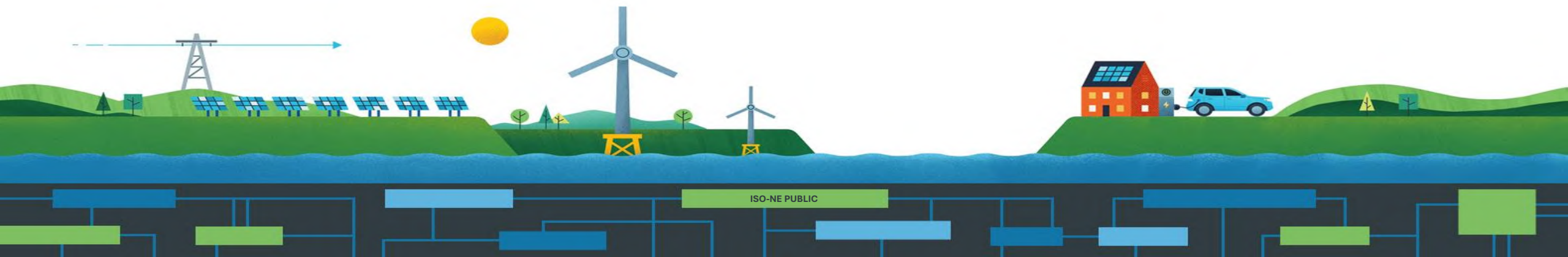
Pay-For-Performance Revisions: Conforming Change to the Billing Policy for External Transactions



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

Shelley Hall

FINANCIAL SYSTEMS & ACCOUNTING MANAGER



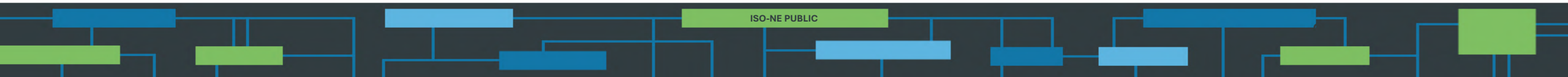
Pay-For-Performance Revisions: Conforming Change to the Billing Policy for External Transactions

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

WMPP ID:
190

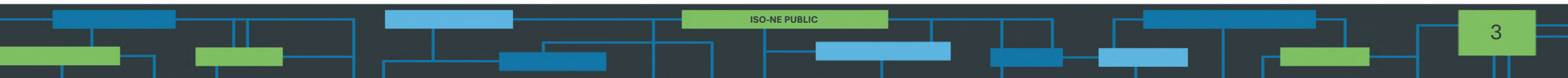
Proposed Effective Date: October 1, 2026

- 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



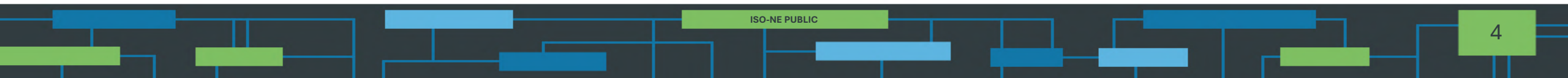
Background

- 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

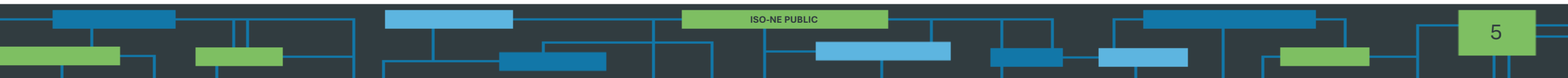
- As a component of PFP, SBE Charges will be billed to Market Participants as a Non-Hourly Charge in the Forward Capacity Market (FCM) Credit bill line
- The ISO is proposing a conforming change to the Billing Policy, Section 2.4(e), *Monthly Forward Capacity Market Charges and Payments*, to include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



Summary of Proposed Tariff or Manual Changes^[1]

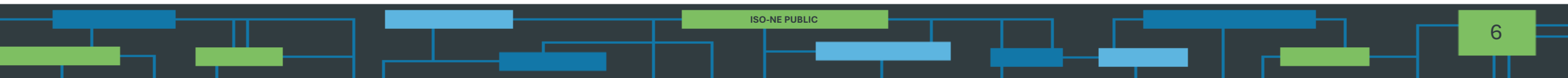
Section	Tariff or Manual Change	Reason for Change
Addition of SBE charges to Section 2.4 – Contents of Statements	“Each Statement for Hourly and Non-Hourly Charges will include all of the following line items that are applicable to the Covered Entity receiving such Statement for the period to which such 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

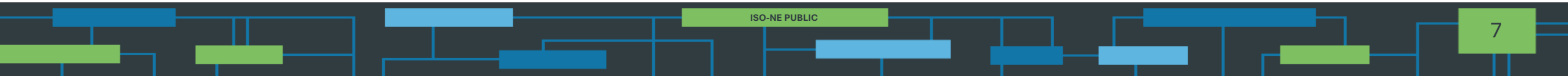
- The ISO is proposing a conforming change to Section 2.4(e) of the Billing Policy to include SBE Charges in Monthly Forward Capacity Market Charges and Payments
- The ISO plans to file the proposed Billing Policy changes in July 2026 with an October 1, 2026 proposed effective date



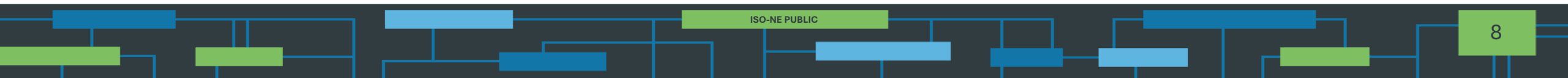
Stakeholder Schedule

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



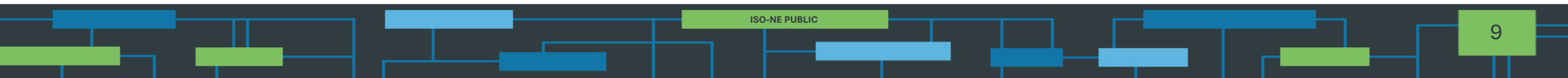
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MEMORANDUM

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:

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

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 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*

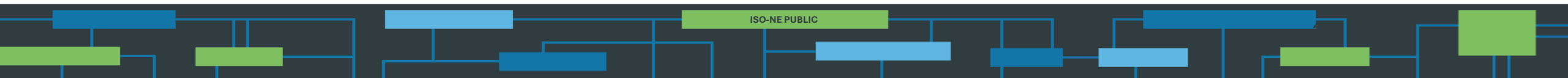
Megan Sweitzer & Enrico De Magistris

LEAD ANALYST & ECONOMIST



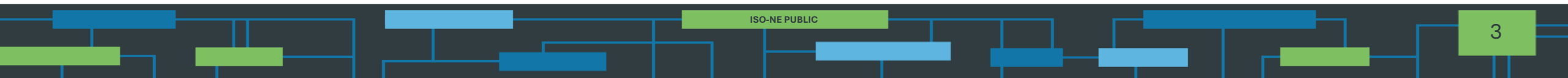
Proposed Effective Date: July 25, 2025

- 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



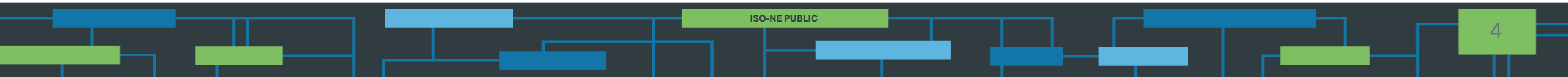
BACKGROUND, REQUIREMENTS, AND DESIGN PRINCIPLES

This section will provide background on the Balancing Ratio and Commission order



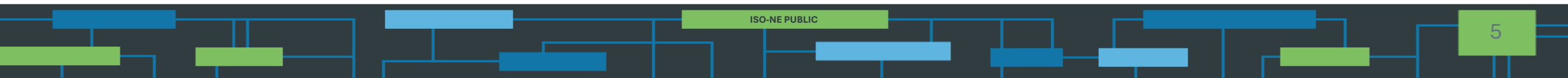
Background

- 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



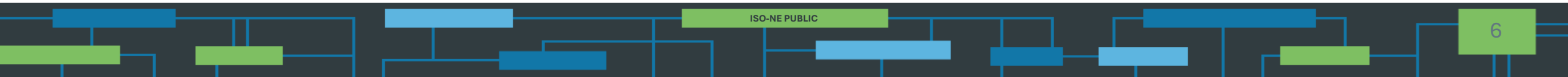
Requirements for Compliance with Order

- 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



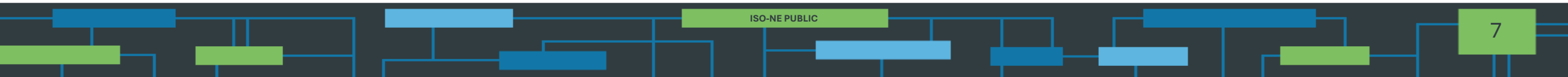
Design Objectives

- 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

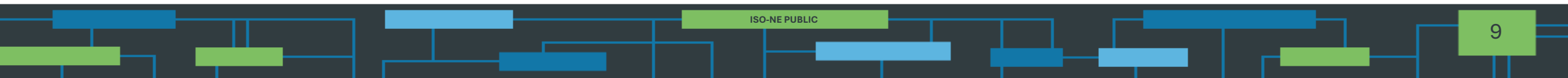


Overview of Proposed Changes

- 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 =

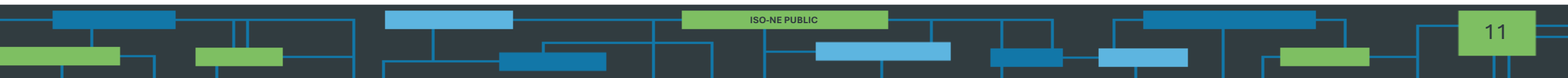
$$\min(\text{PPR}, \text{Negative Performance Payments}_{\text{month}} / \text{Overperformance}_{\text{month}} \text{ MWh})$$

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

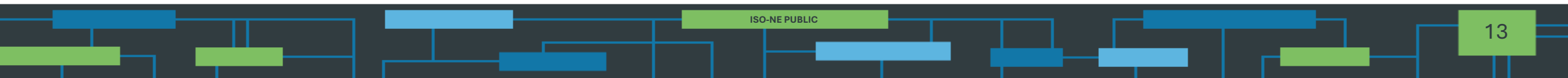
- There is more overperformance than underperformance with the BR capped at 1.0
- Fewer performance charges accrue from less underperformance
- More overperformance credits owed due to lower BR
- Fewer charges divided by higher positive performance results in an effective PPR of \$4,669
- CSO resources 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

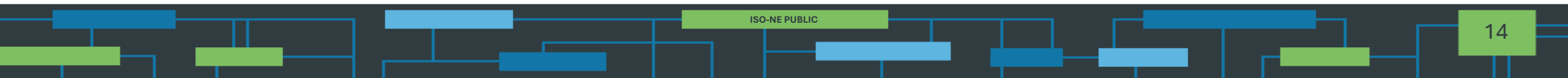
CONFORMING CHANGES

Conforming changes to Capacity Performance Bilaterals, mitigation, and capacity zones



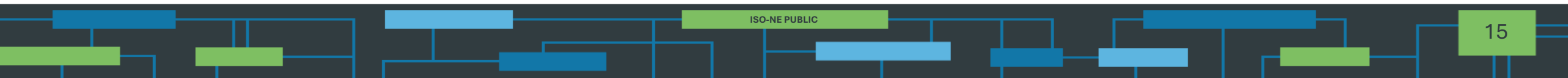
Capacity Performance Bilaterals

- 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

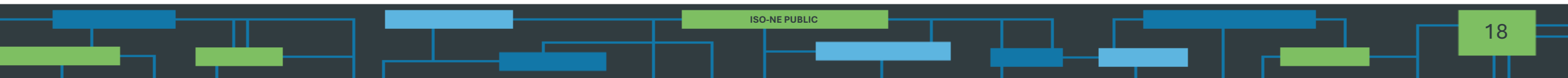
Conforming Changes to Market Power Mitigation Process

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

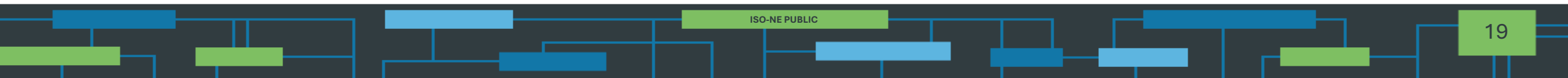
Conforming Changes for Zonal CSC Event

- 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



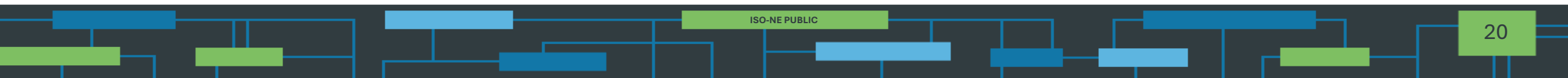
Conclusion

- 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



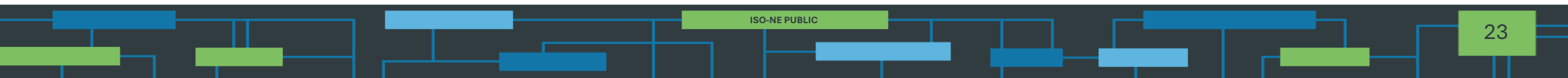
Questions



Acronyms Used in this Presentation

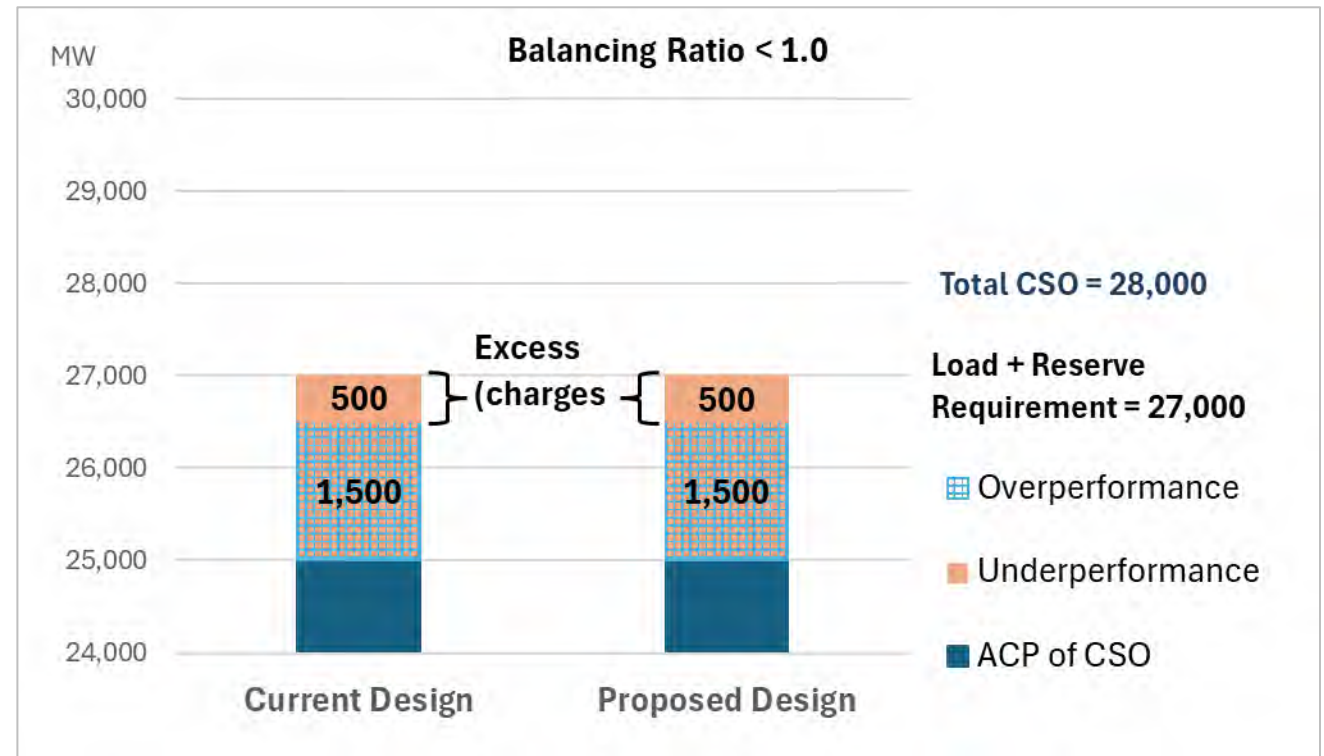
- ACP = Actual Capacity Provided
- BR = Balancing Ratio
- CPP = Capacity Performance Payment
- CPS = Capacity Performance Score
- CSC = Capacity Scarcity Condition
- CSO = Capacity Supply Obligation
- FERC = Federal Energy Regulatory Commission
- IMM = ISO-NE Internal Market Monitor
- NEPGA = New England Power Generators Association
- PFP = Pay for Performance
- PPR = Performance Payment Rate
- RR = Reserve Requirement

APPENDIX



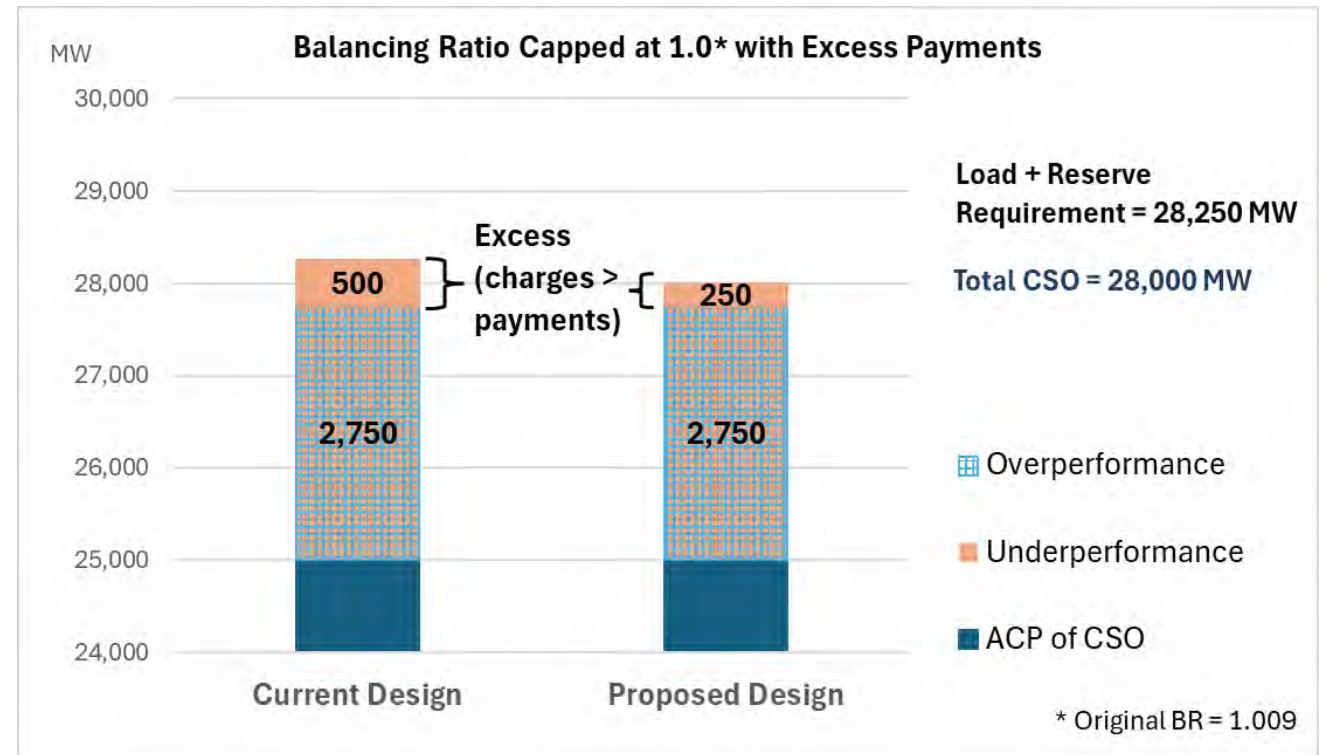
Scenario 1A: Balancing Ratio < 1.0

- 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 = $\$9,337/\text{MWh}$



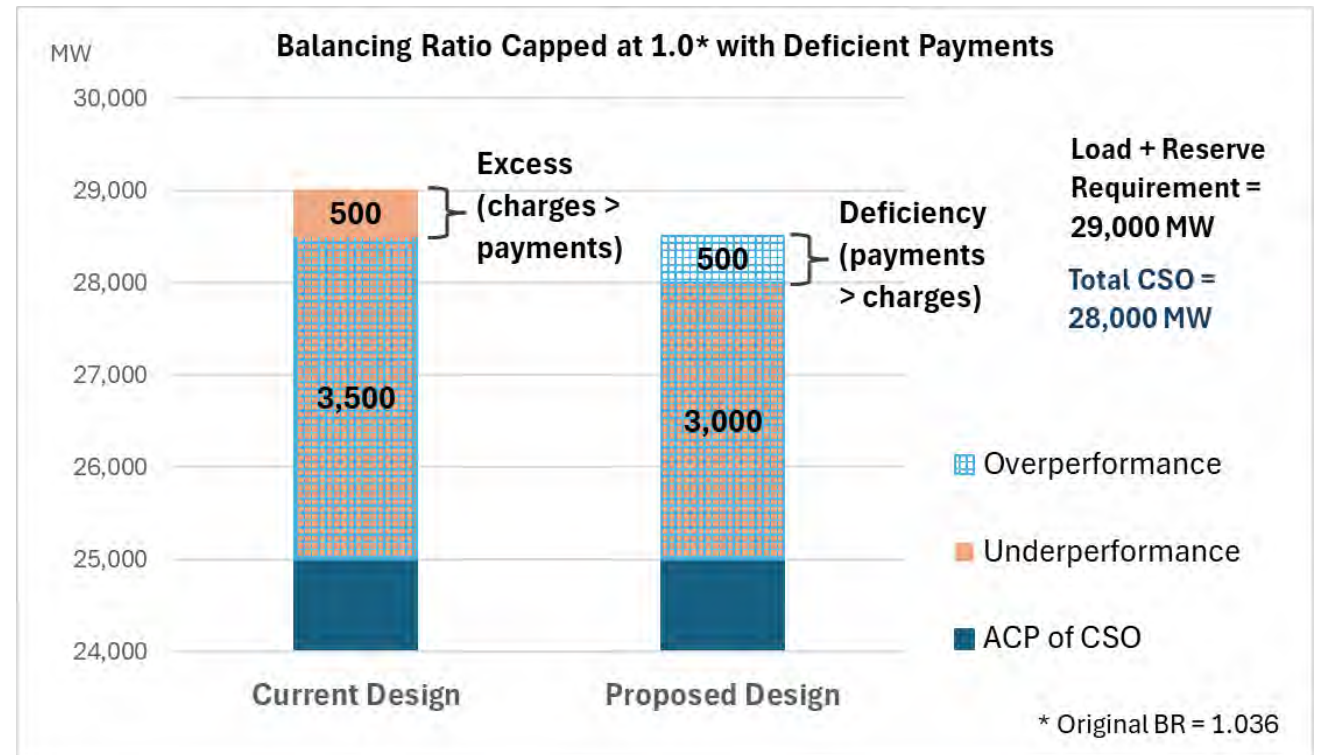
Scenario 2A: Balancing Ratio Capped at 1.0 with Excess Capacity Performance Payments

- 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*

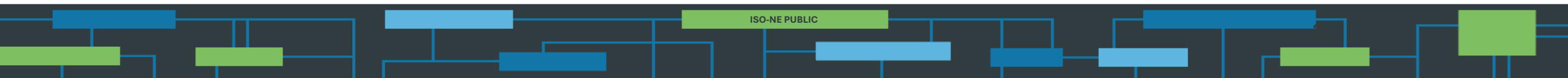
Megan Sweitzer & Enrico De Magistris

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

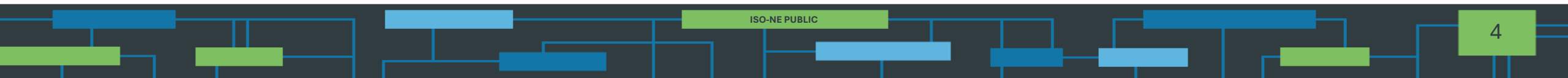


Overview of Proposal

- 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

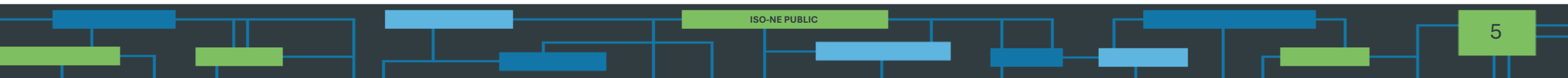
BALANCING FUND ALLOCATION

Additional details on the balancing fund allocation, stop loss, and zonal Capacity Scarcity Conditions (CSC)



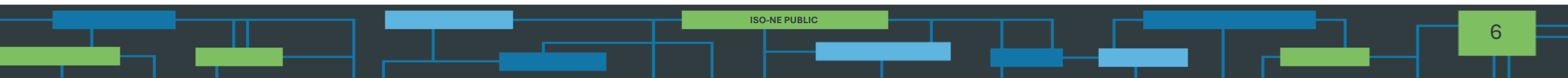
Balancing Fund and Stop Loss Allocation Process

- 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

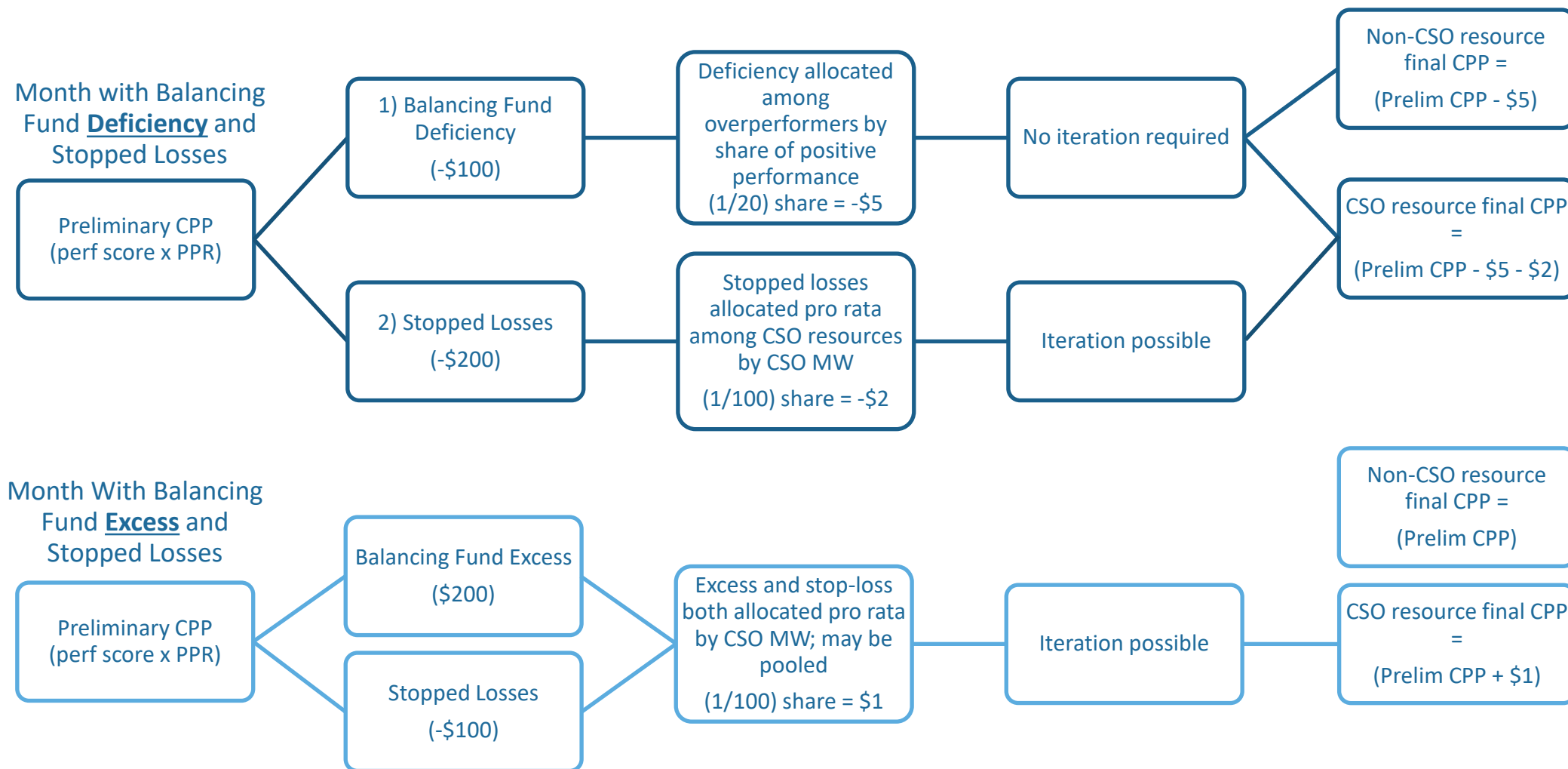


Balancing Fund and Stop Loss Allocation Process (cont.)

- 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



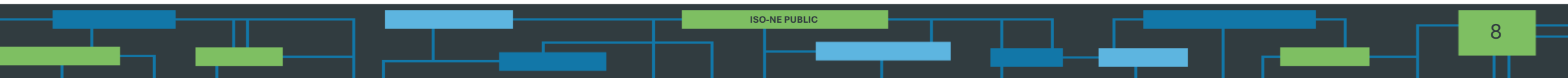
Balancing Fund and Stop Loss Allocation Process



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

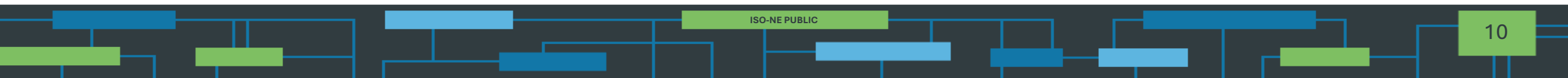
PPR=\$3,500	Event 1 (Zonal)	Event 2 (System)
Balancing Ratio	0.95	1.0 (from 1.03)
CSO	10,000	28,000
Load+RR	9,500	28,850
ACP	9,300	28,350
Hours	1	1
Underperformance	1,000	2,000
Overperformance	800	2,350
Performance Charges Accrued	3,500,000	7,000,000
Performance Payments at Full PPR	-2,800,000	-8,225,000
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

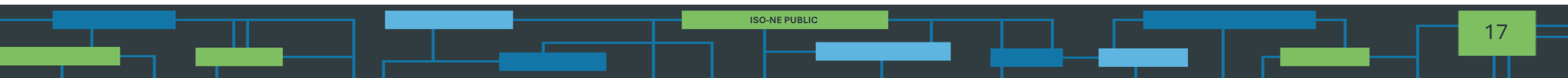
Tariff Section	Tariff Change	Reason for Change
III.13.7.4 (c)	Create new subsection (c): “If a deficiency of Capacity Performance Payments exists due to one or more resources reaching the stop-loss limit described in Section III.13.7.3, the deficiency shall be charged to all resources subject to a Capacity 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

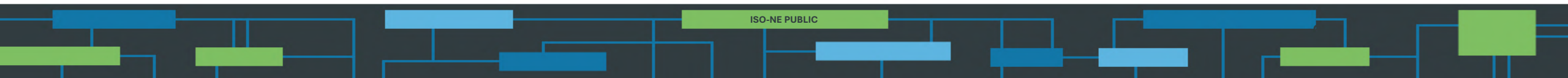


Pay-For-Performance: Financial Assurance Changes for External Transactions and Balancing Ratio

NEPOOL PARTICIPANTS COMMITTEE
JUNE 16-18, 2026 SUMMER MEETING, AGENDA ITEM #8
Attachment F
WMPP IDs:
189 & 190

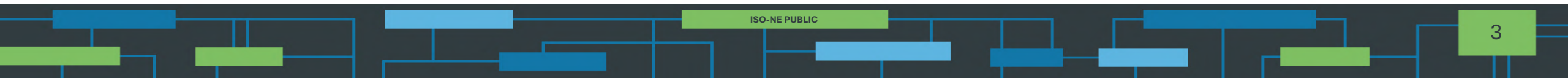
Proposed Effective Date: October 1, 2026

- 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



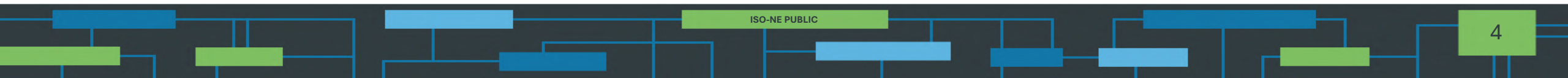
EXTERNAL TRANSACTIONS

FAP Revisions



Background

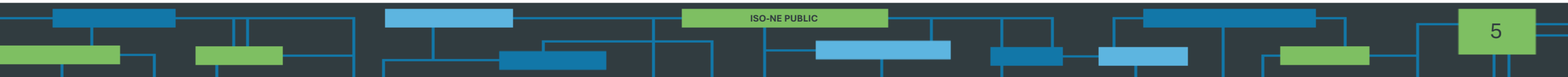
- During the April 17th BFS meeting, the ISO proposed updating the FAP to include a new financial assurance requirement
- **SBE FA = PPR * SBE MW * Scarcity Hours**
 - PPR = Performance Payment Rate
 - SBE MW = The Market Participant's Average SBE MWs across all CSCs occurring within the relevant group 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

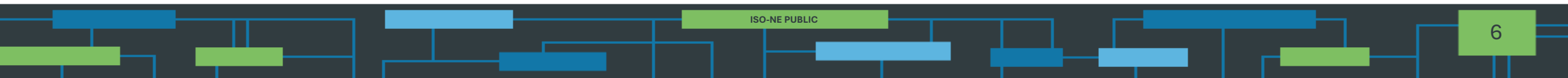
- **SBE FA = (PPR * SBE MW * Scarcity Hours) – MEC⁽¹⁾ – PMEC⁽¹⁾**
- PPR = Performance Payment Rate
- SBE MW = the Designated FCM Participant's average MW of System-Backed Exports across all Capacity Scarcity Conditions in the relevant group of months in the three Capacity Commitment Periods immediately 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



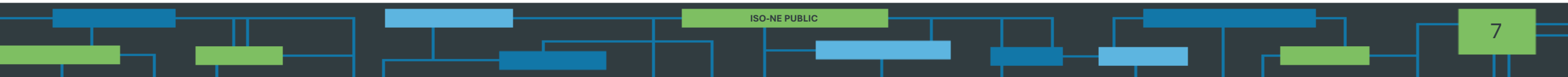
Example: SBE FA Calculation

- **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
 - **$\$3,500 \text{ PPR} * 80 \text{ SBE MW} * 2 \text{ Scarcity Hours} = \$560,000$**



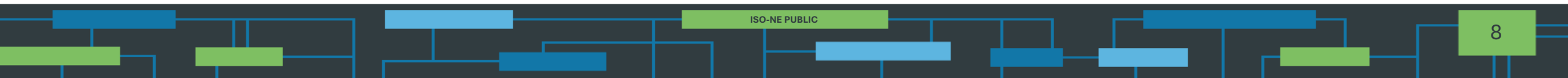
Impact of Proposal

- 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



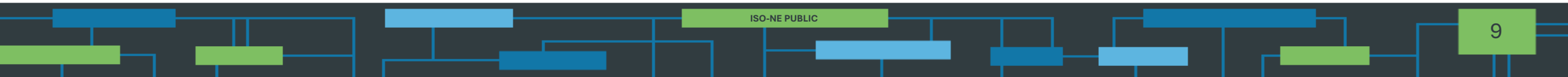
BALANCING RATIO

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

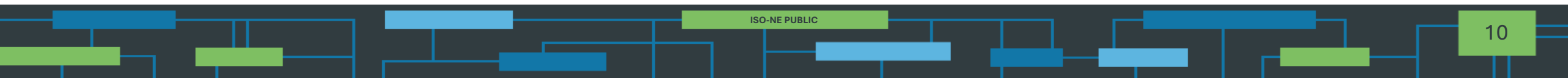


Example: ABR Calculation

- 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

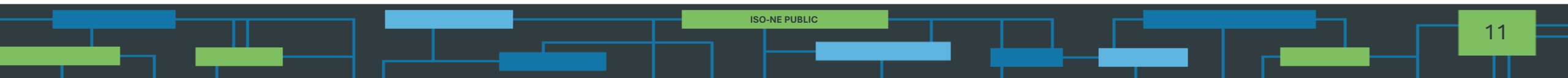
CSC Event Date	Season	Number of CSC Intervals	Original BR	Recalculated BR (SBE's removed and cap of 1.0)
Jun 2024	Summer	6 (0.5 hours)	0.869	0.847
Aug 2024	Summer	22 (1.833 hours)	0.903	0.883
Jun 2025	Summer	37 (3.083 hours)	1.031	0.999
Nov 2025	Shoulder	6 (0.5 hours)	0.696	0.634

- 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

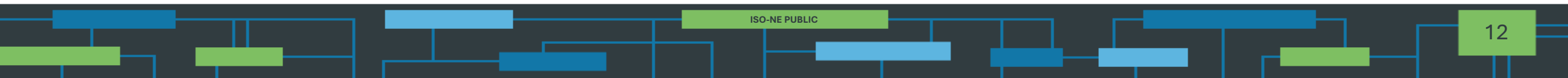
A Designated FCM Participant with System-Backed Export transactions, as defined in Section III.13.7.2.A and Section III.15.8.2.A of Market Rule 1, must include SBE Financial Assurance in the calculation of its FCM Financial Assurance Requirements under the ISO New England Financial Assurance Policy.

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

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

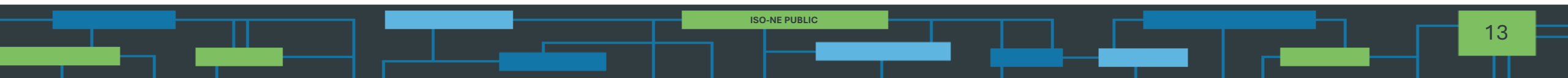
Where:

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.

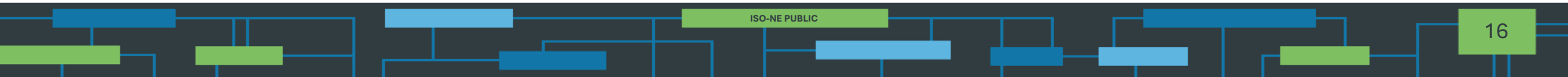
FAP Redlines: ABR

- 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.

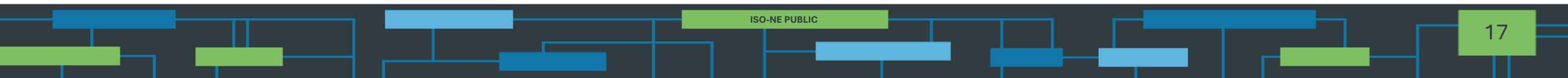
FAP Redlines: Administrative Changes

- 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



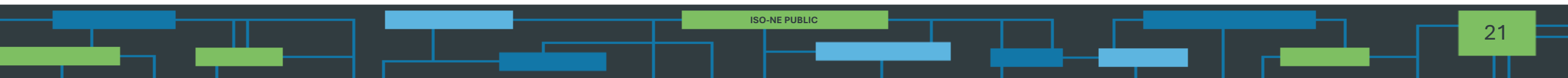
About the Presenter

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

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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

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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 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

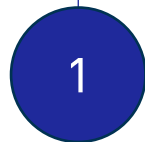
- The PPR is part of a two-settlement system; changing the second step of the settlement after the first step has been determined is inappropriate. This would be akin to modifying the calculation of the real-time energy price for tomorrow after the day-ahead energy market had cleared.
- The Monthly Stop 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

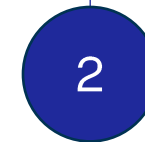
First Forward Capacity Market (FCM) Settlement Step

- 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](#)

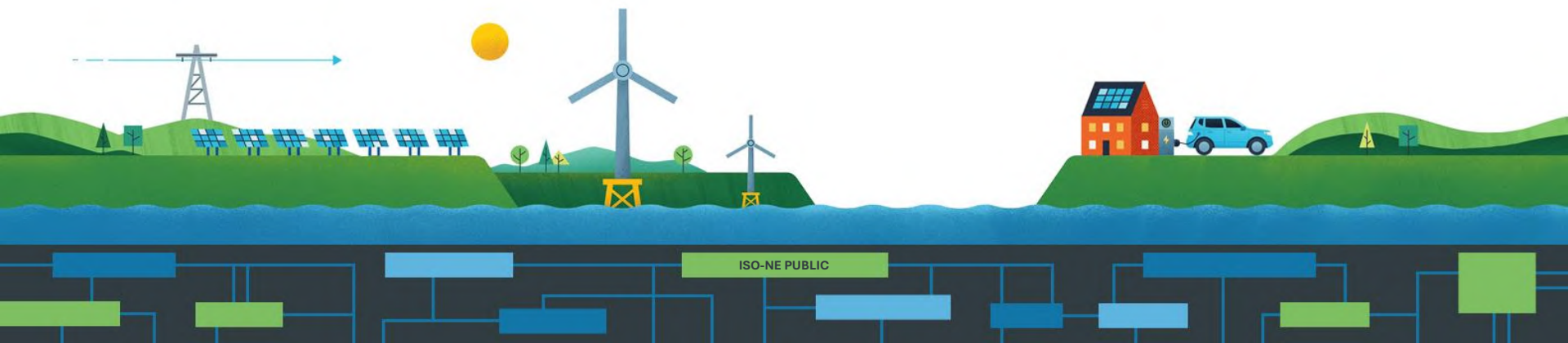
Day-Ahead Ancillary Services Post-Implementation Adjustments



*Targeted changes to the DA A/S design
based on IMM recommendations*

Ben Ewing

TECHNICAL MANAGER



Day-Ahead Ancillary Services Post-Implementation Adjustments

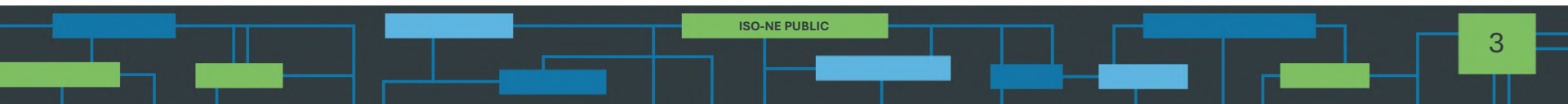
WMPP ID
192

Proposed Effective Date: Early Q4 2026 (targeting implementation on 10/22/26 for clearing of 10/23/26)

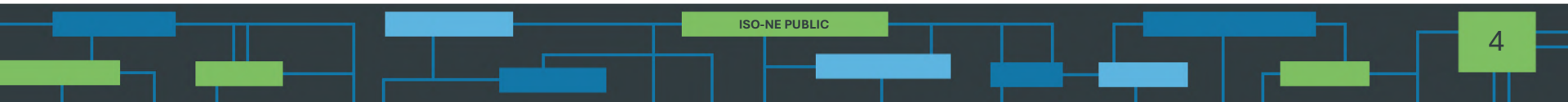
- In February 2026, the ISO's Internal Market Monitor (IMM) issued a set of [DA A/S recommendations](#), with two goals:
 - Enhance the cost-effectiveness of the market design based on observations over first year of operation
 - Cost effectiveness may be enhanced by addressing inefficiencies observed 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

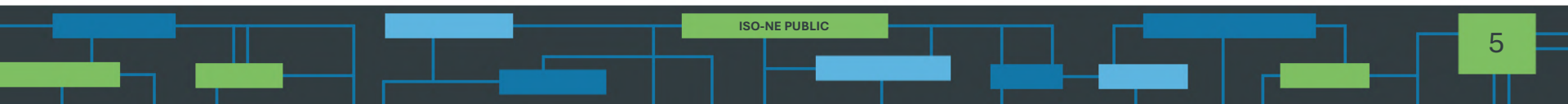


FORECAST ENERGY REQUIREMENT DEMAND QUANTITY ADJUSTMENT



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

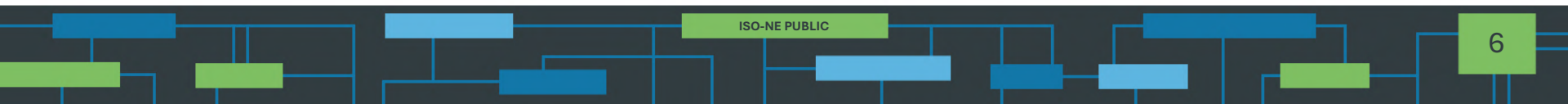


DAM and FER Background

- 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:

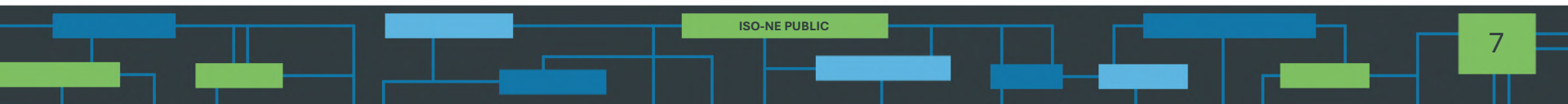
$$\text{Generator}_{\text{DA Energy}} + \text{Import}_{\text{DA Energy}} + \text{EIR} \geq \text{FER DQ} + \text{Export}_{\text{DA Energy}}$$

- 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



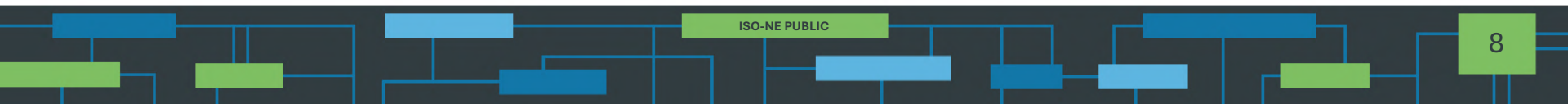
RAA Process Background

- 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

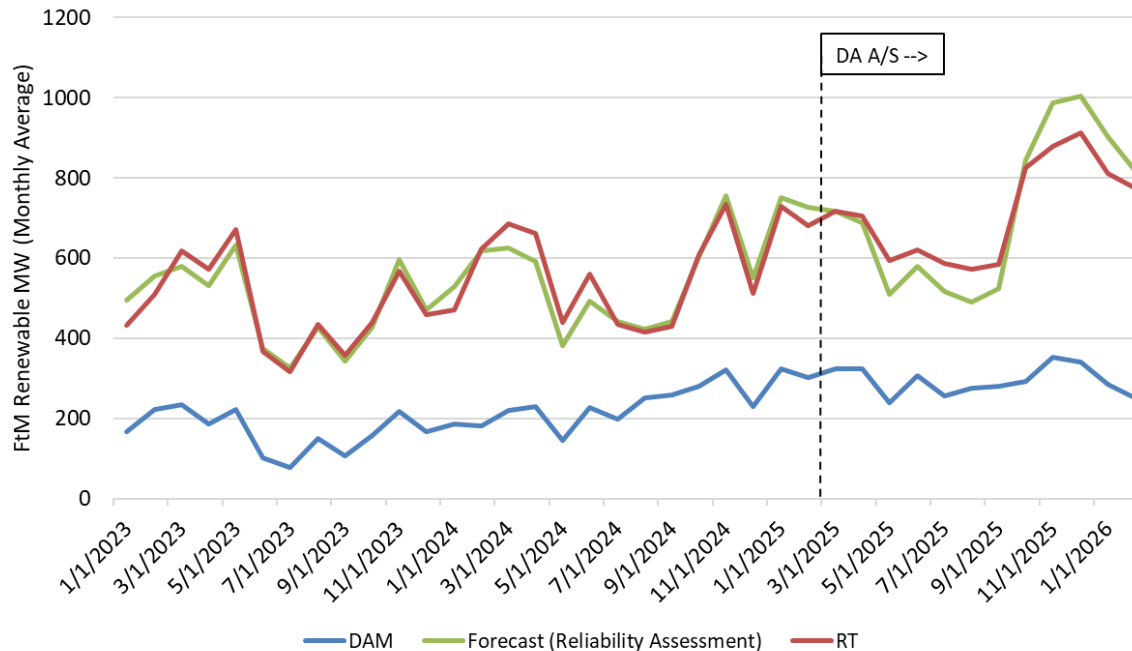


DAM vs RAA - FtM Wind/Solar Accounting

- **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*)



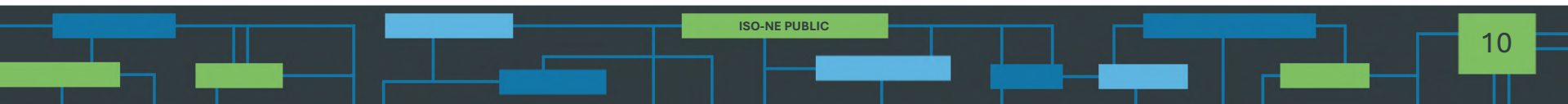
- Varies month-to-month, but on average FtM W/S clear ~40% of forecast in DAM
- This share has not increased with DA A/S implementation

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

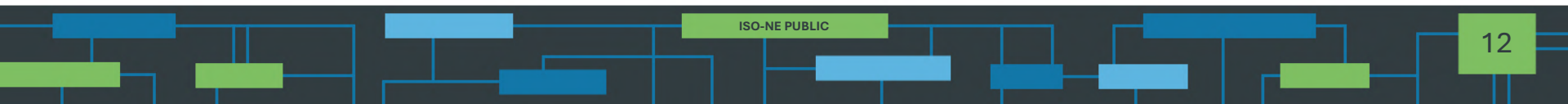
Statistic	FER DQ Adjustment MW (FtM RAA MW - FtM DA Clear MW)
25th percentile	162
Median	370
Average	422
75th Percentile	607
95th Percentile	1,039

- 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

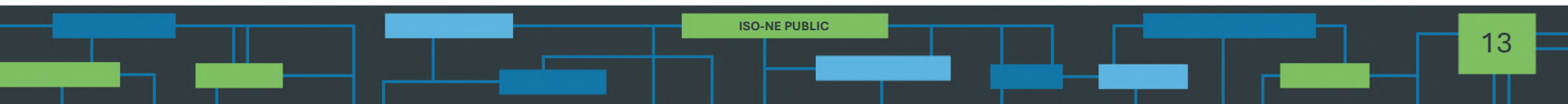
Data Timeframe:
Mar 2025 - Feb 2026

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

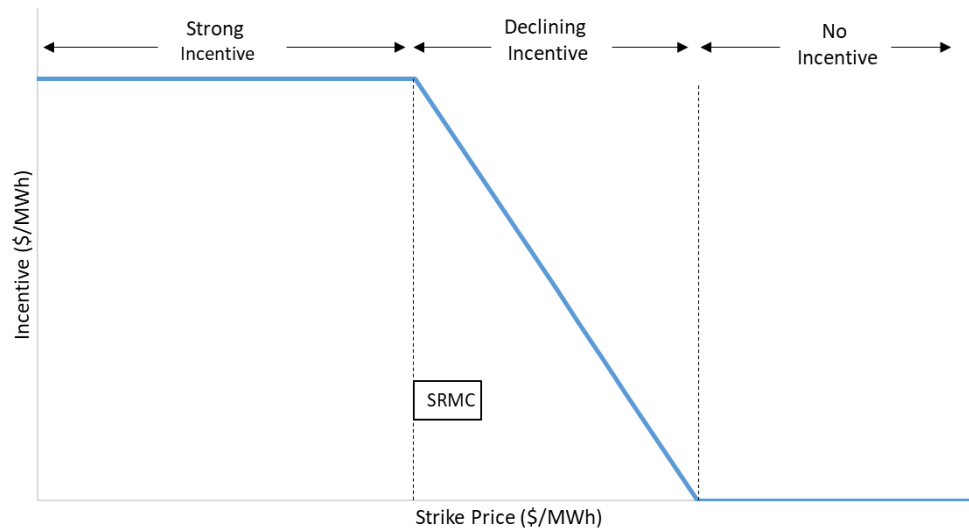
- IMM recommends an upward adjustment to the Strike Price (K) to better align it with the short-run marginal cost (SRMC) of DA A/S providers
 - Specifically, IMM recommends consideration of dynamically applying a floor to K based on the SRMC of a combustion turbine (CT)
- **Objective:** Better align 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%	n/a

- 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

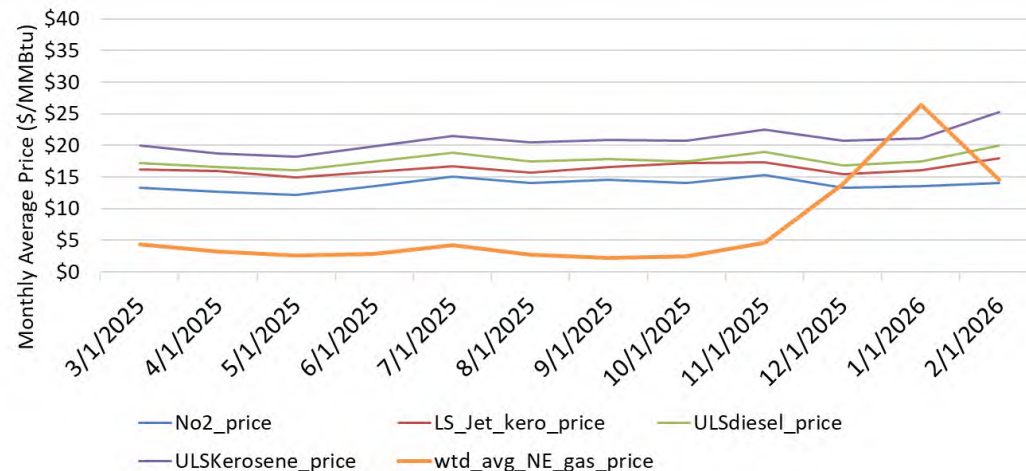
Data Timeframe:
Mar 2025 - Feb 2026

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

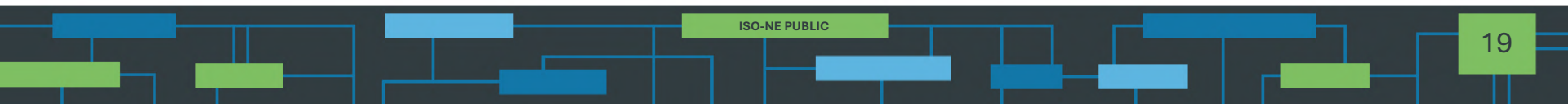
CT - Fuel	DA A/S Cleared GWh	Percent DA A/S Awards Cleared on CTs
Oil - ULKerosene	6,478	48%
Natural Gas	3,491	26%
Oil - Diesel	2,016	15%
Oil - No2	1,144	8%
Oil - LS Jet Kero	470	3%

- Distillate fuel prices were stable during the past year, but differ by fuel



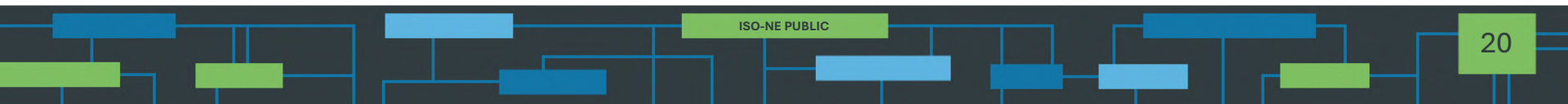
ISO Proposal Overview

- 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

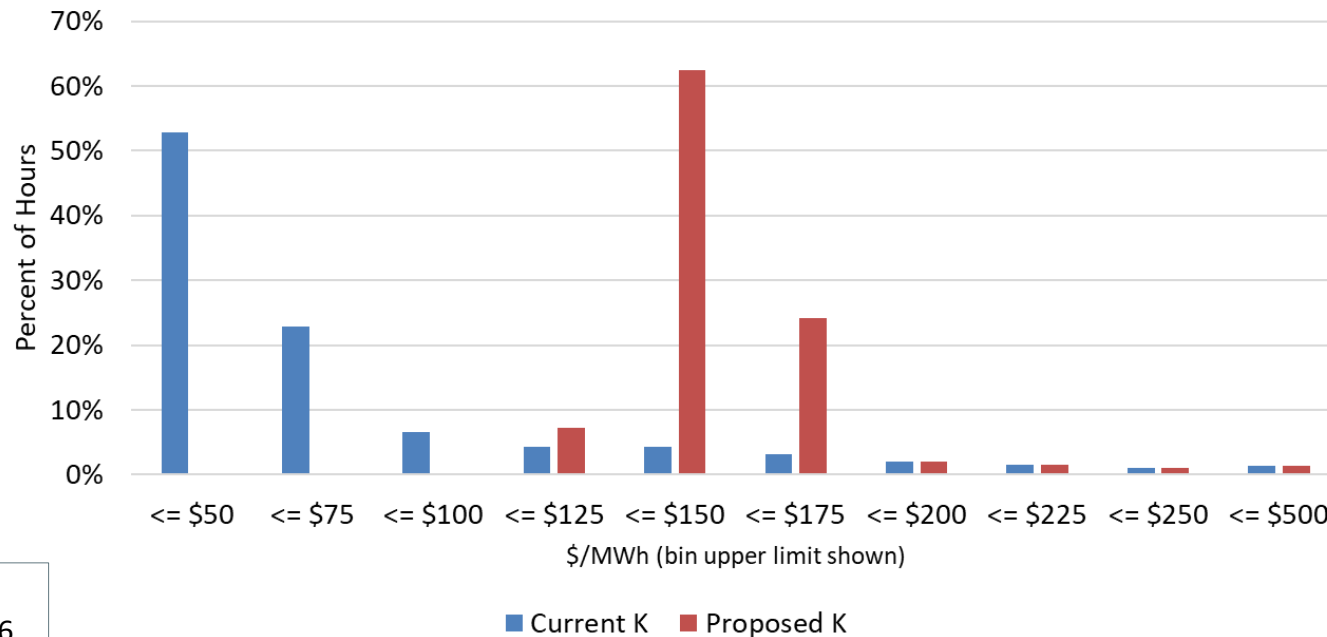
- Heat Rate of an efficient CT
 - Propose to use 9 MMBtu/MWh in implementation
- Fuel-Related Costs
 - Use the lowest cost of the four distillate fuels used by CTs observed to clear DA A/S
 - Costs reflect both fuel price and emissions costs (in \$/MMBtu)
 - Natural gas is not considered (*More on this 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

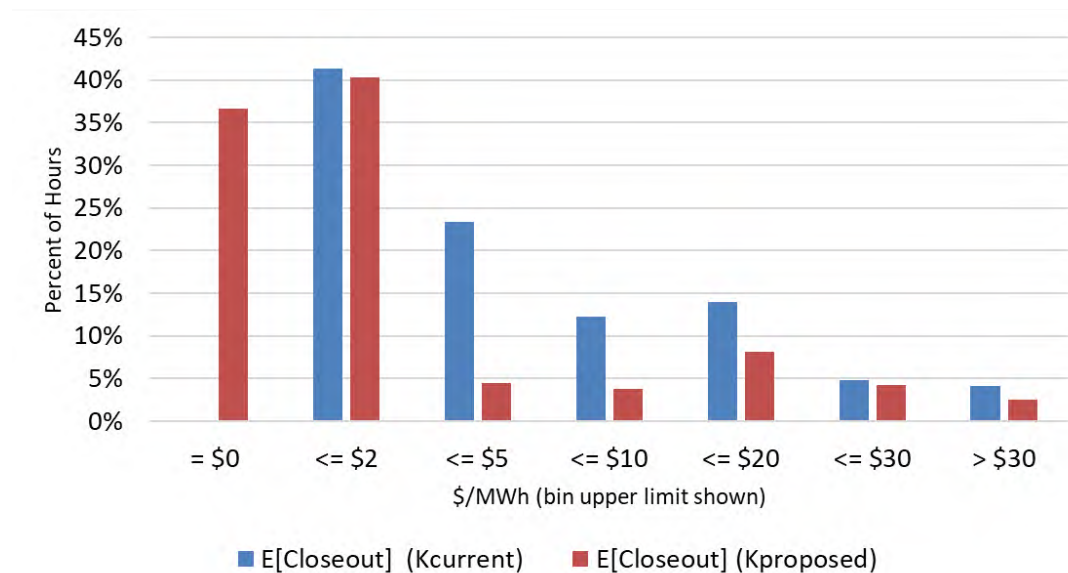
- Proposed strike price floor affects K in 90% of hours (obviating the adder), and has no effect on K in the other 10% of hours
- In this other 10% of hours, expected system conditions were sufficiently tight that $E[\text{RT LMP}] + \$10$ exceeded the proposed floor for K
 - This includes all hours 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

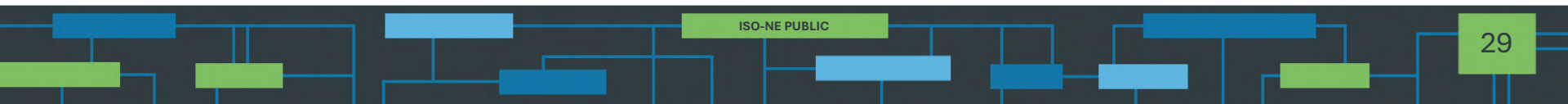
- Expected Closeout is a key component of competitive DA A/S offer prices, and factors directly into the Benchmark Level (BL), Conduct Test Threshold (CTT), and Impact Test Threshold (ITT) parameters used in mitigation

Benchmark Level = $E[\text{Closeout}] + \text{Avoidable Input Cost (AIC)}$

CTT = $\text{Max}(\$2, 2 \times E[\text{Closeout}]) + 1.5 \times \text{AIC}$

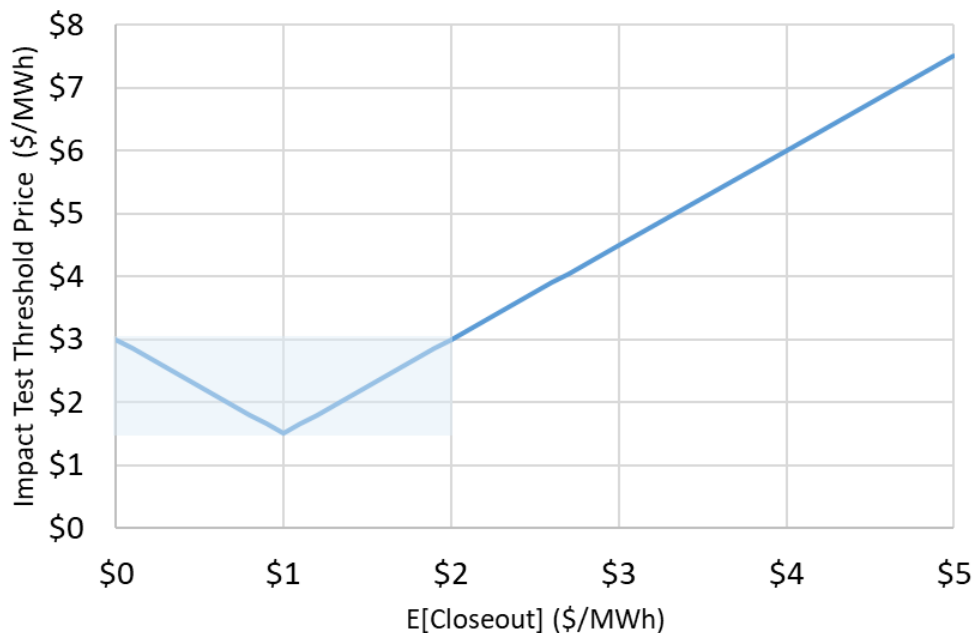
ITT = $1.5 \times \text{Median}[\text{CTT} - \text{BL}]$

- 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*)

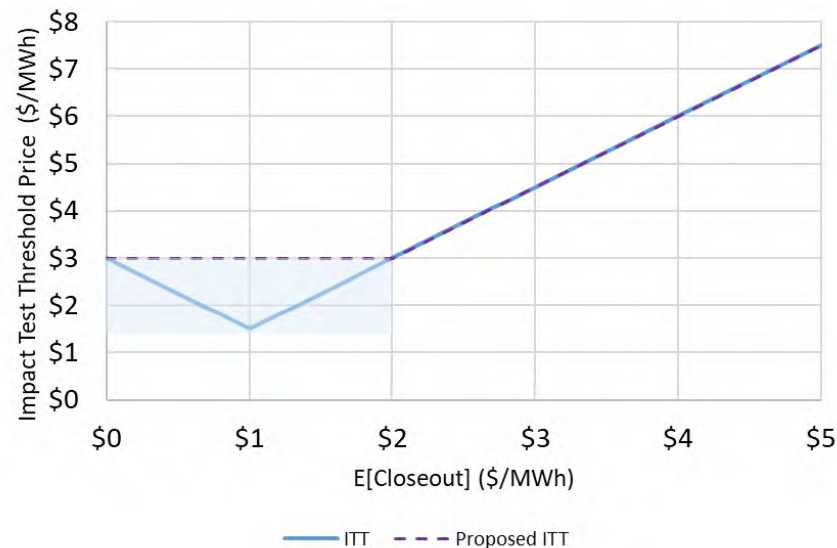
- Under the current design, the ITT initially becomes more stringent as $E[\text{Closeout}]$ increases from $\$0/\text{MWh}$ (illustrative example below)
 - This is an effect of the $\$2$ CTT floor
 - When $E[\text{Closeout}] = \$0$, the ITT is $\$3$
 - In the range $\$0 < E[\text{Closeout}] < \$2$, 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

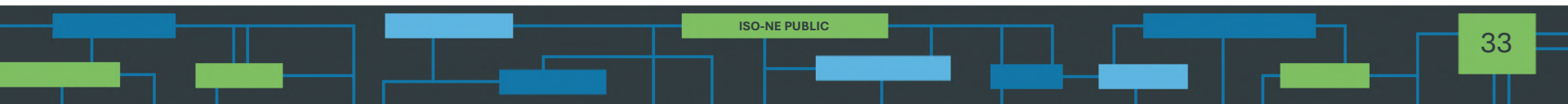


Expected Effect of Floor on Costs – Initial Qualitative Considerations

- 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

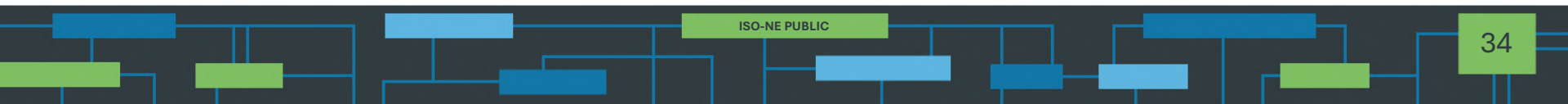
Strike Price Adjustment – Key Takeaways

- 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



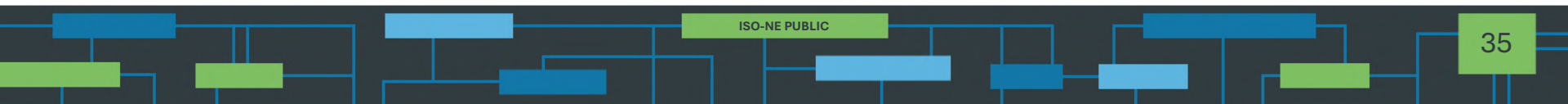
DA NCPC CLEAN-UP ITEM

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

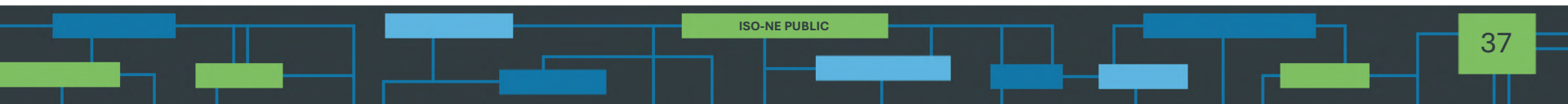
- Consider a 1 MW cleared DA Import that is on the margin for energy supply:

Concept	Value (\$/MWh)
DA Import Supply Offer	\$60
DA LMP	\$50
FER Price	\$10

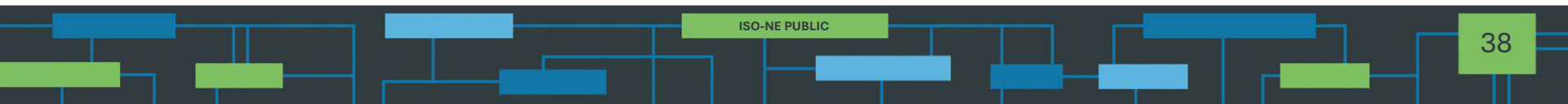
- Assume this import has no corresponding RT transaction, and is therefore ineligible for the FER Credit
- Current DA NCPC Credit Calculation:
 - Hourly Revenue = DA LMP = \$50
 - Hourly Cost = Supply offer = \$60
 - DA NCPC Credit = $\max(\text{Cost} - \text{Revenue}, 0) = \$10$
- This import effectively 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

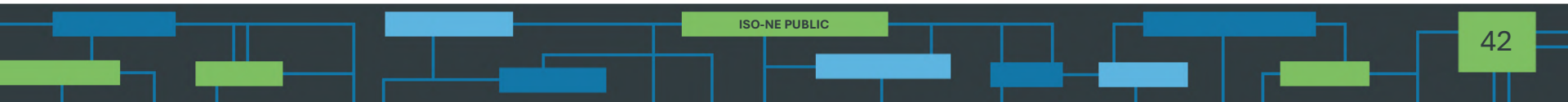
Stakeholder Schedule

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

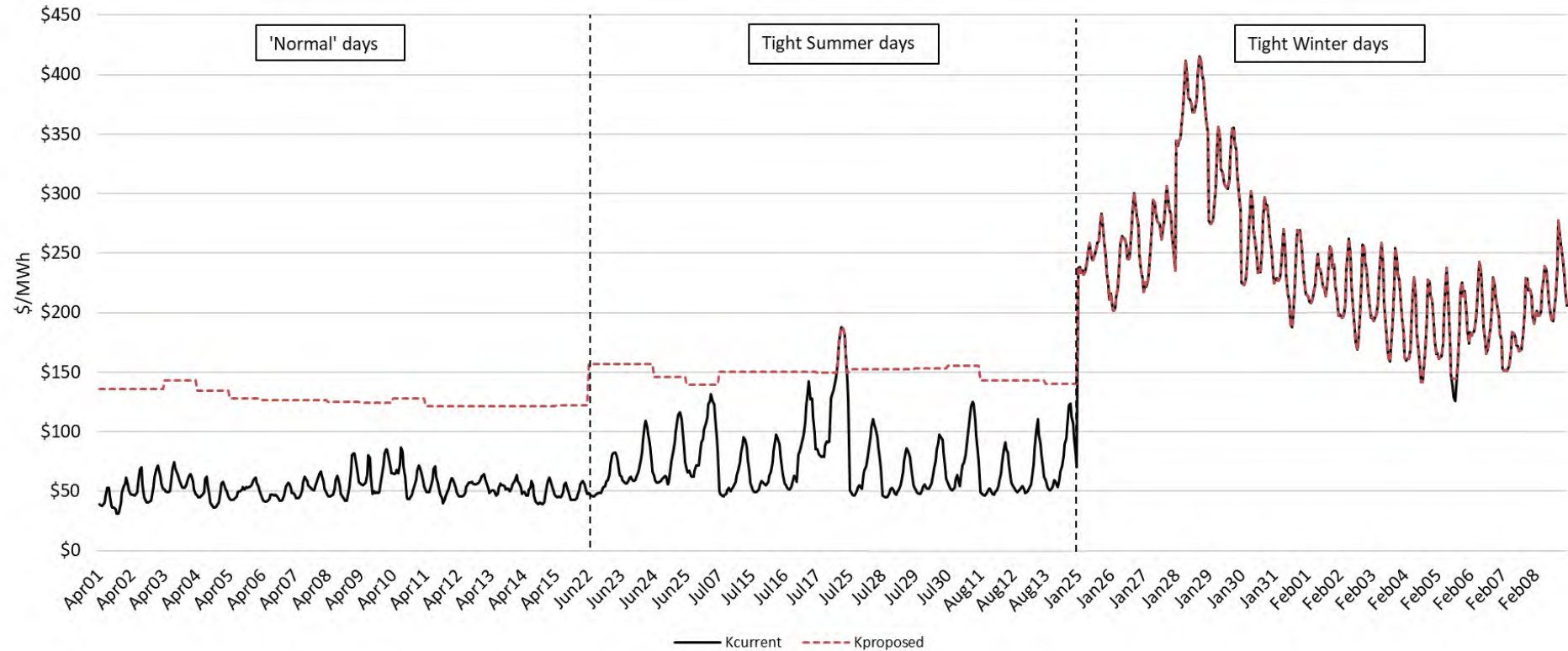
Questions



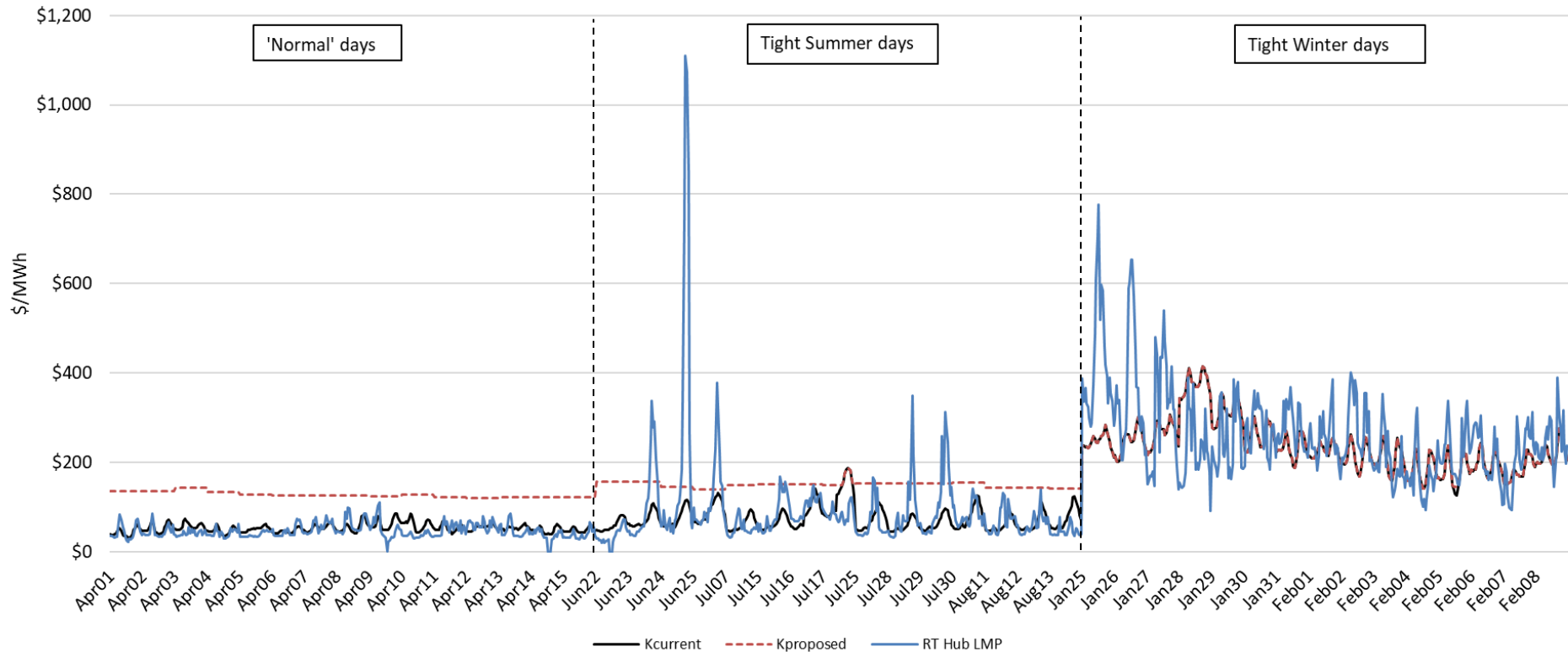
APPENDIX



Strike Price proposal on representative days



Strike Price proposal on representative days (*cont'd*)



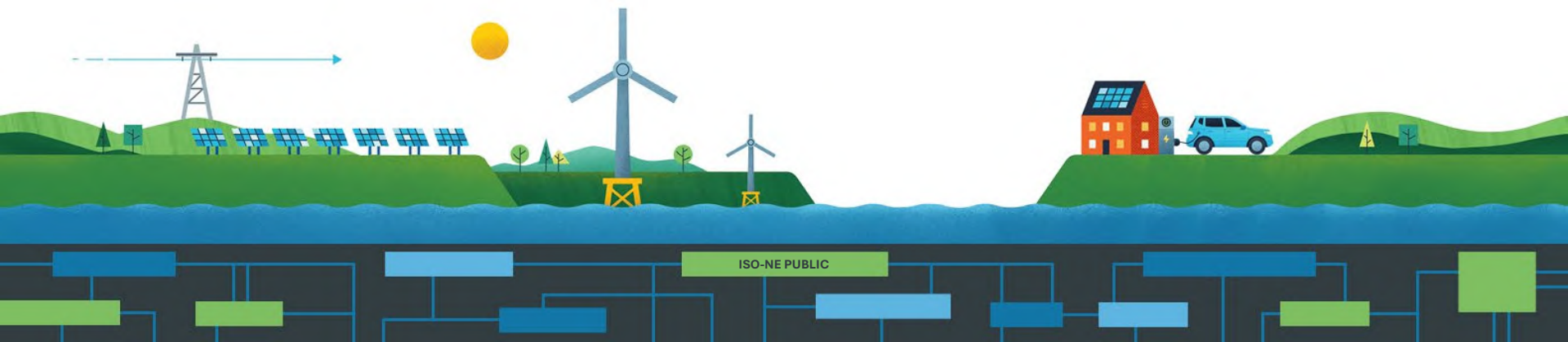
Day-Ahead Ancillary Services Post-Implementation Adjustments



*Targeted changes to the DA A/S design
based on IMM recommendations*

Ben Ewing

TECHNICAL MANAGER



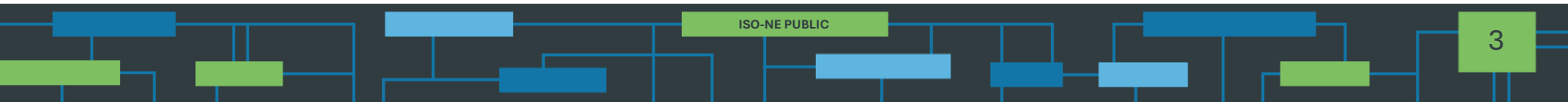
Day-Ahead Ancillary Services Post-Implementation Adjustments

WMPP ID
192

Proposed Effective Date: Early Q4 2026 (targeting implementation on 10/22/26 for clearing of 10/23/26)

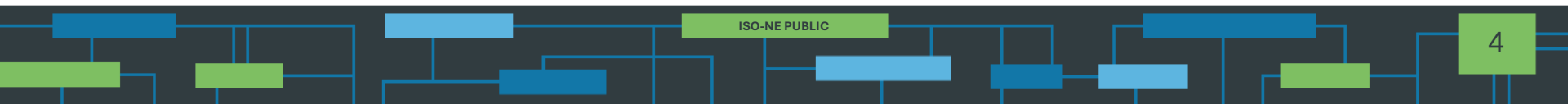
- In February 2026, the ISO's Internal Market Monitor (IMM) issued a set of [DA A/S recommendations](#), relating to three aspects of the DA A/S design:
 - Forecast Energy Requirement (FER) Demand Quantity (DQ)
 - Non-Performance Factor (NPF)
 - Strike Price (K)
- In April 2026, ISO proposed a set of 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



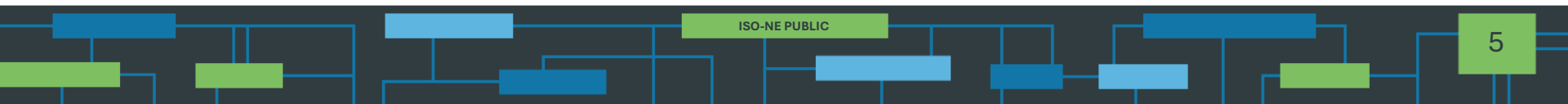
FER Demand Quantity Adjustment Proposal

- 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 –

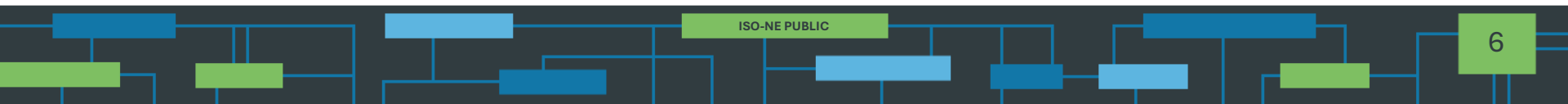
$\max(\text{FtM W/S Forecast} - \text{Expected FtM W/S Cleared Energy and EIR}, 0)$

- “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

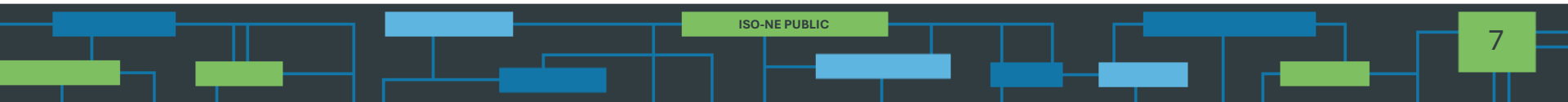


Reliability Considerations

- 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%

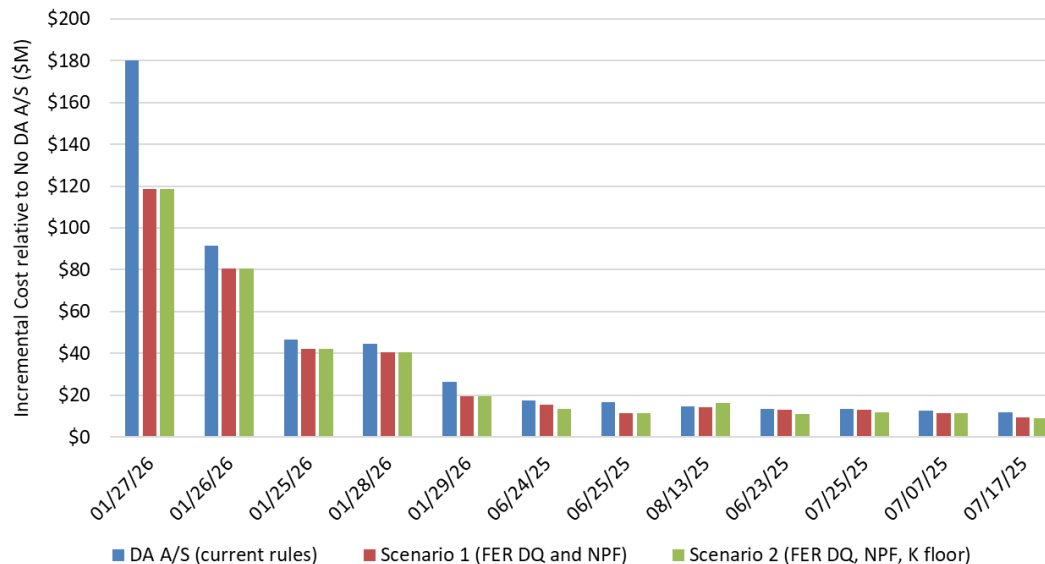
Table shows average estimated clearing prices from Mar 2025 – Feb 2026

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

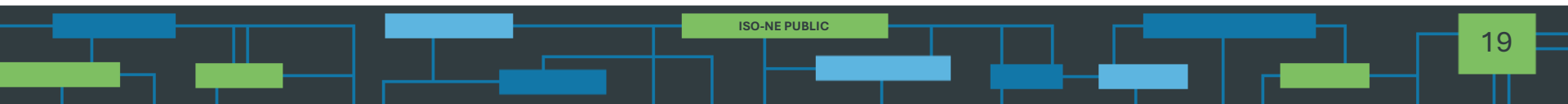
- During the first year with DA A/S, twelve days accounted for ~50% of the incremental cost of the DA A/S market design (i.e., comparing Current Rules scenario to No DA A/S scenario)
- Proposal is estimated to reduce incremental costs on those historical dates by ~\$103M (35%)
 - Significant impact on 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

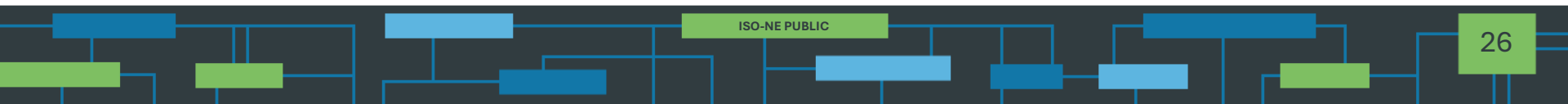
Summary of Proposed Tariff Changes

Section III.F.2.3.1.3 Hourly Revenue (subsection of III.F.2.3.1 DA External Transaction Import NCPC Credits)

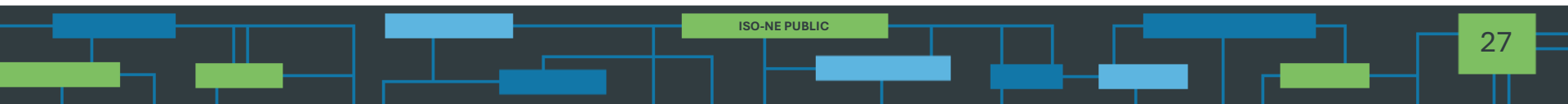
Tariff Section	Tariff Change	Reason for Change
III.F.2.3.1.3	Insert “not” and “credit.” Revised sentence: “The Day-Ahead revenue for a pool-scheduled External Transaction import at an External Node for an hour is equal to the cleared Day-Ahead transaction amount (MW) for the hour multiplied by the Day-Ahead 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

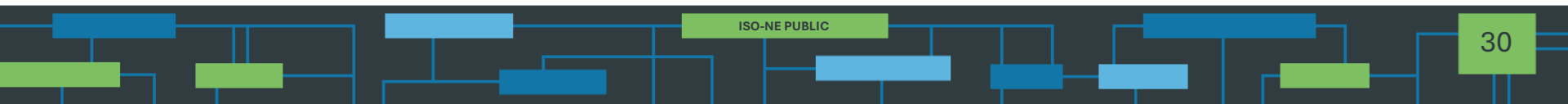
Stakeholder Committee and Date	Scheduled Project Milestone
Markets Committee April 14-16, 2026	Overview of ISO proposal
Reliability Committee April 22, 2026	Review change to the Non-Performance Factor
Markets Committee May 12-13, 2026	Estimate of market impacts and initial review of proposed Tariff language
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

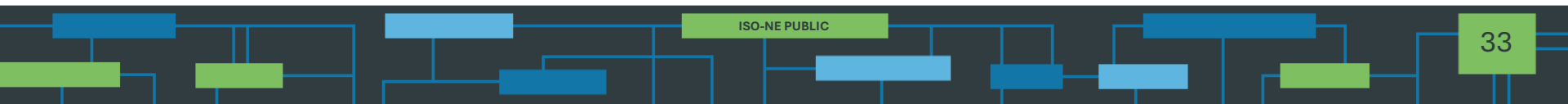
Id	Category	No DA A/S	Current DA A/S Rules (\$M)	Scenario 1: FER DQ and NPF Adjustments (\$M)	Delta (Current Rules - Scenario 1) (\$M)	Percent Delta (Current Rules vs Scenario 1) (%)	Incremental DA A/S Costs (Current Rules - No DA A/S) (\$M)	Incremental DA A/S Costs under Partial Proposal (Scenario 1 - 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%

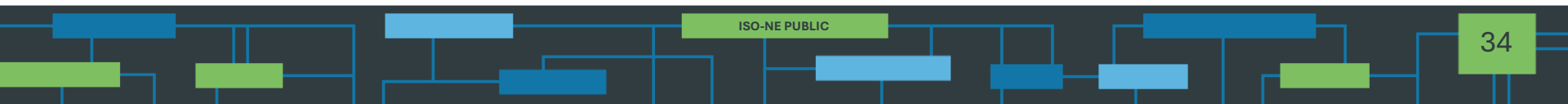
APPENDIX 2

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 $\$20/\text{MWh}$)

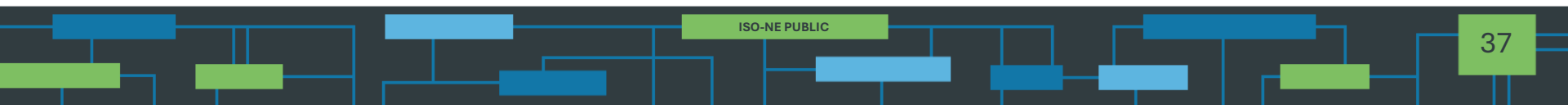
DAM Inputs				DAM Outputs	
Resource	Ecomax (MW)	Energy Offer (\$/MWh)	FRS Offer Price (\$/MWh)	Cleared DA Energy (MW)	Cleared FRS (MW)
A	700	\$36		700	
B	100	\$39	\$0.26	100	0
C	100	\$50	\$0.30	10	90
D	50	\$70		40	
Total:				850	90

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

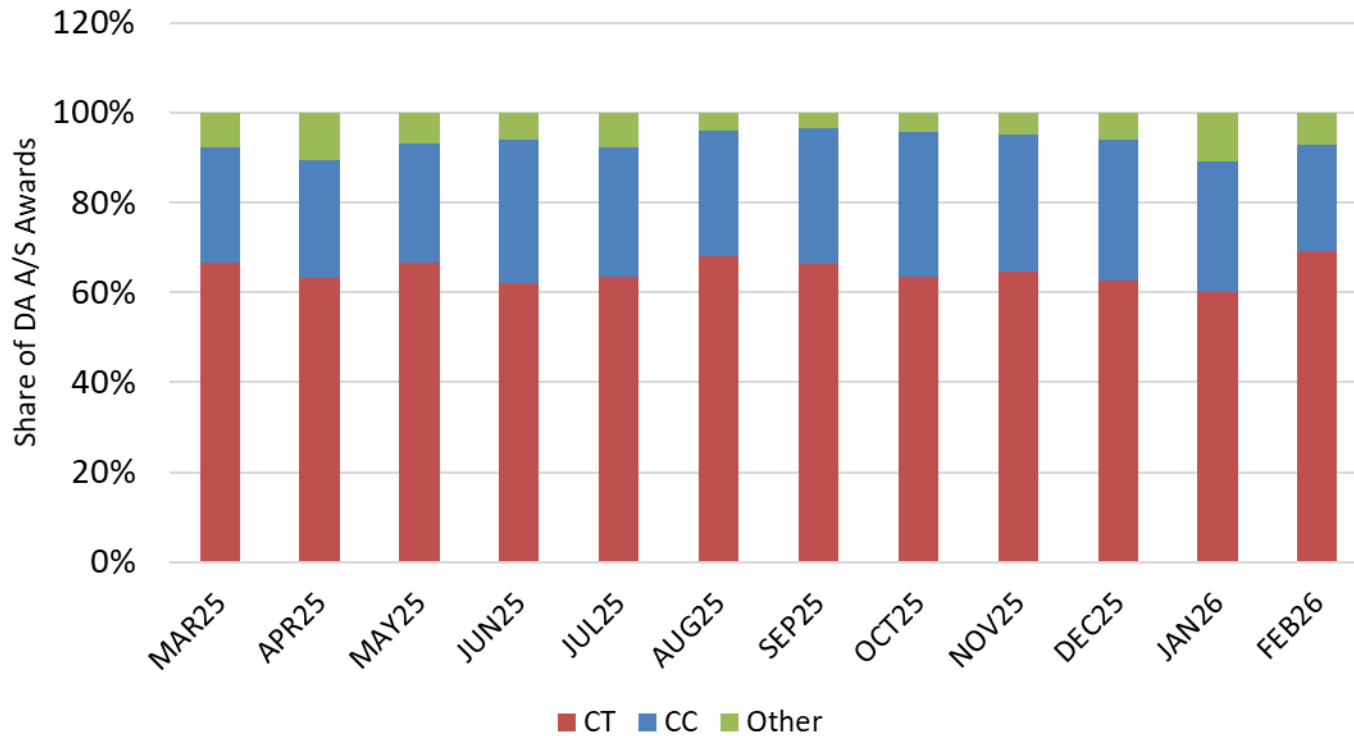
*Information requested at the April 2026 Markets
Committee Meeting*



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

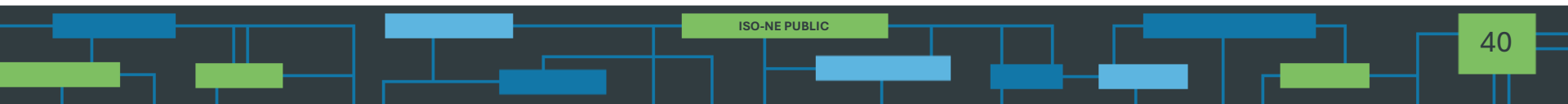
Monthly DA A/S Supply Mix



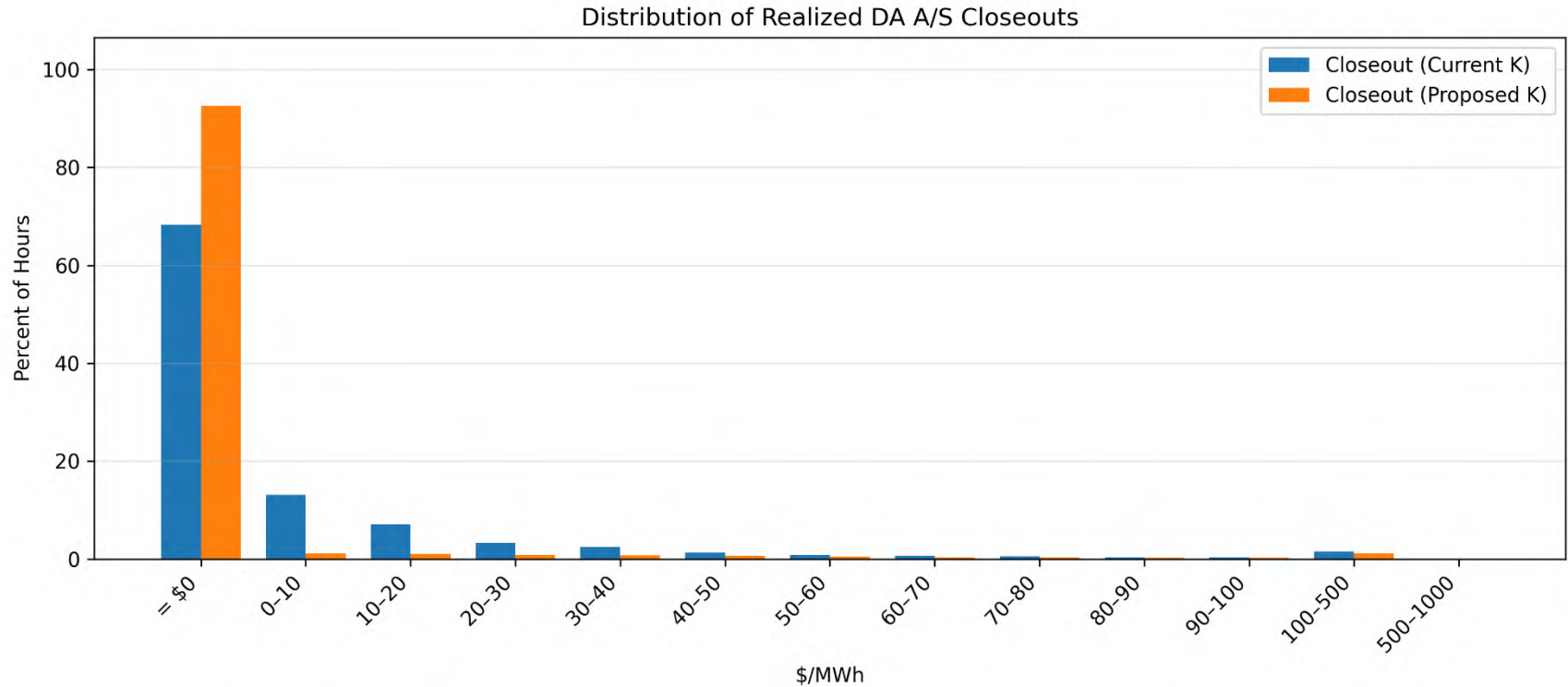
- DA A/S supply mix is consistent over time

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

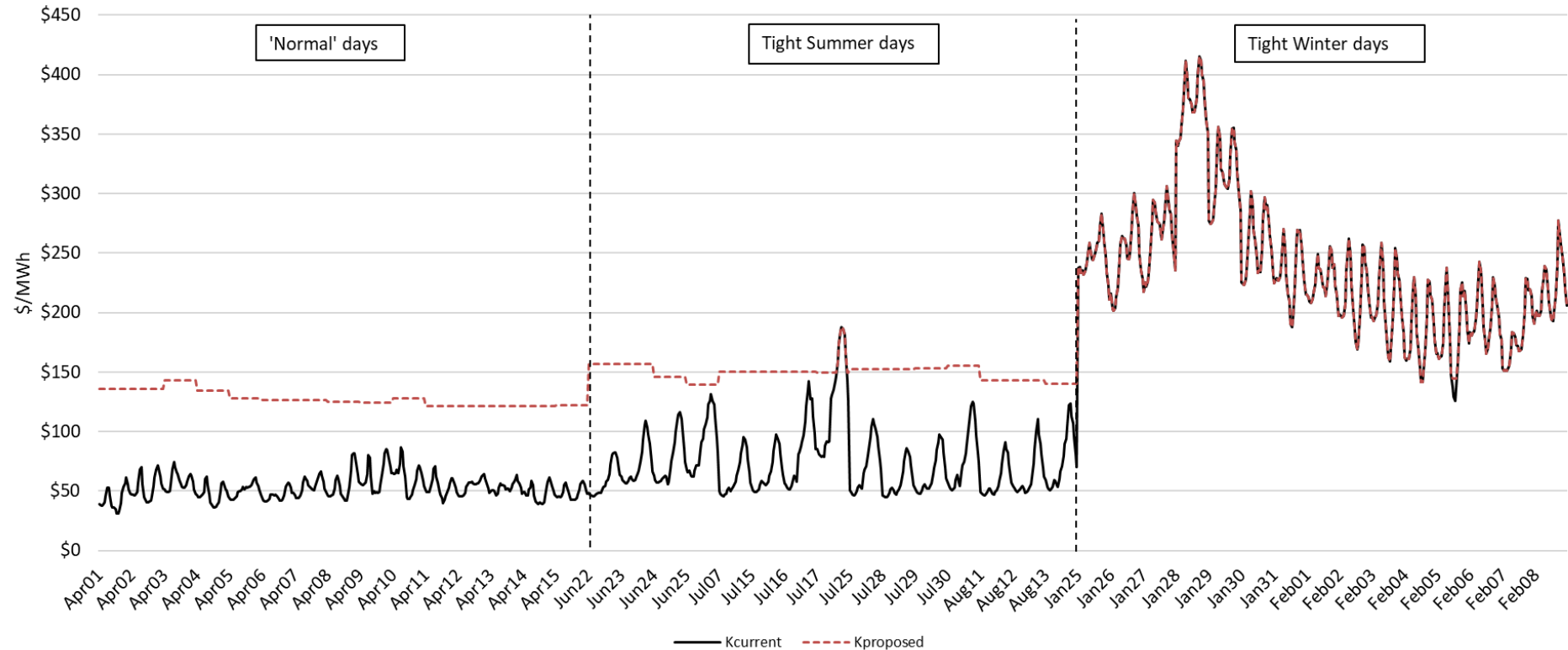


Realized Closeout Costs

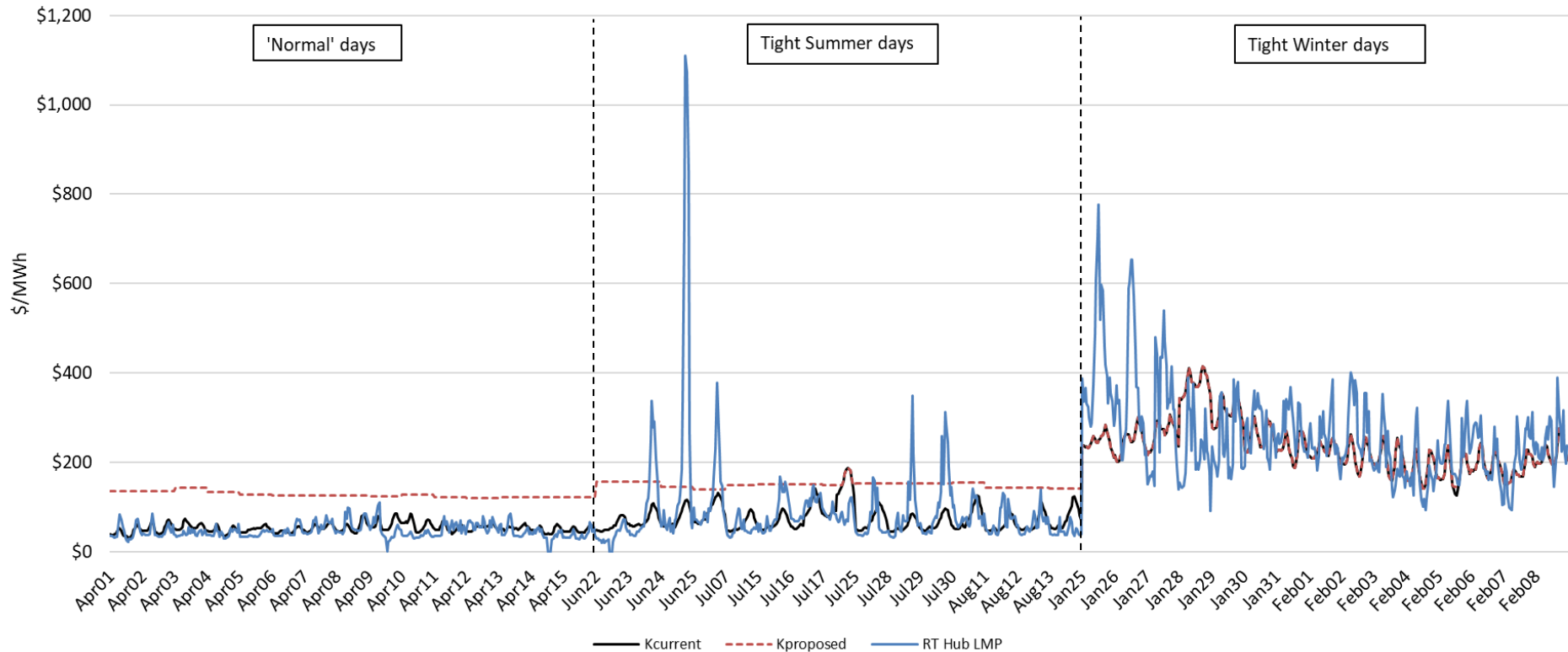


	Actual K	Proposed K
Hours with Non-Zero Closeouts (% of hours)	32%	7%
Average Closeout (\$/MWh)	9	5
95 th Percentile Closeout (\$/MWh)	45	21
99 th Percentile Closeout (\$/MWh)	126	107

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).

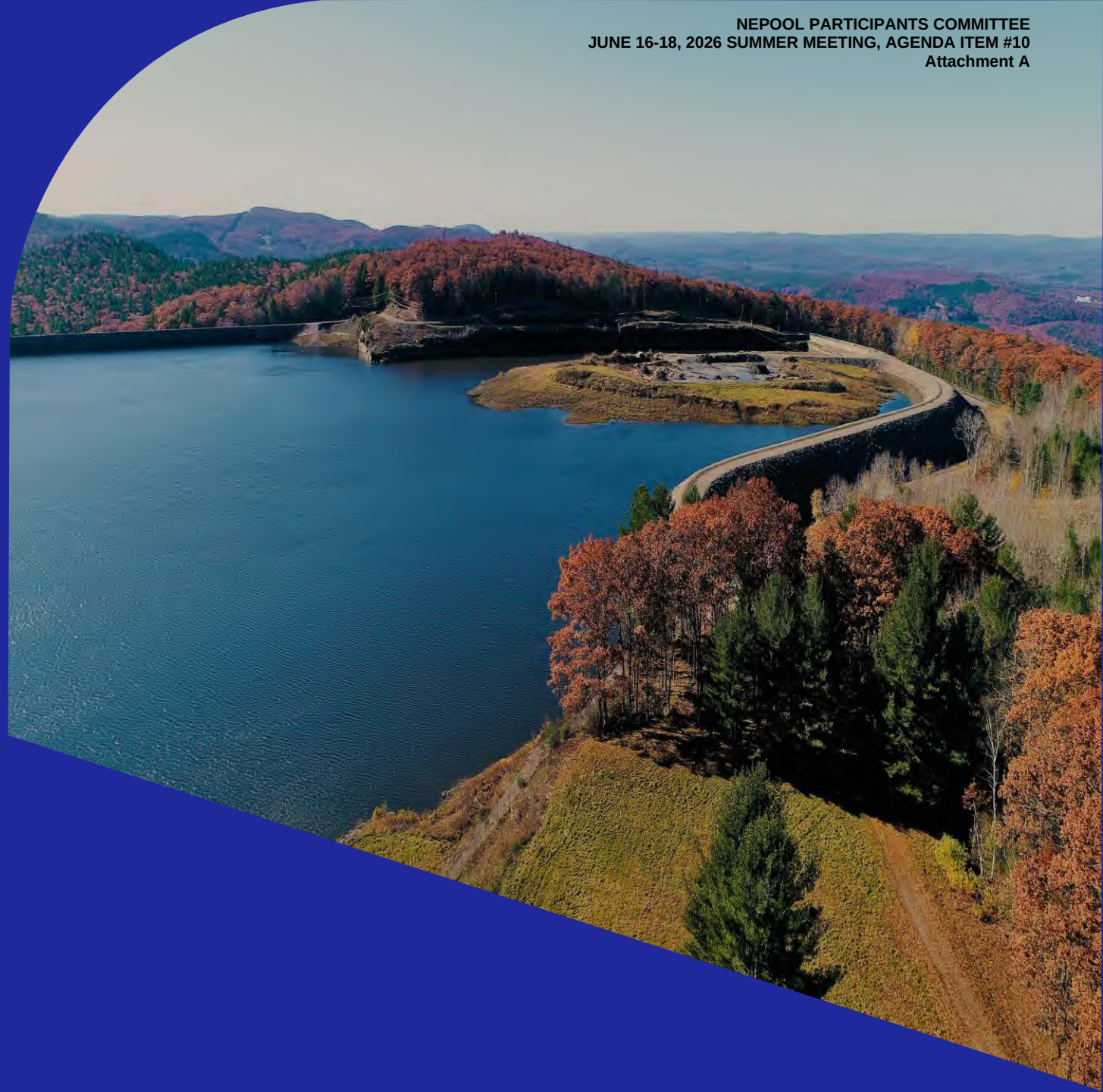
(Vote 2 – Passed) Agenda Item 3.A – ISO-NE's Proposed Day-Ahead Ancillary Services Post-Implementation Adjustments – Unamended Main Motion

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%

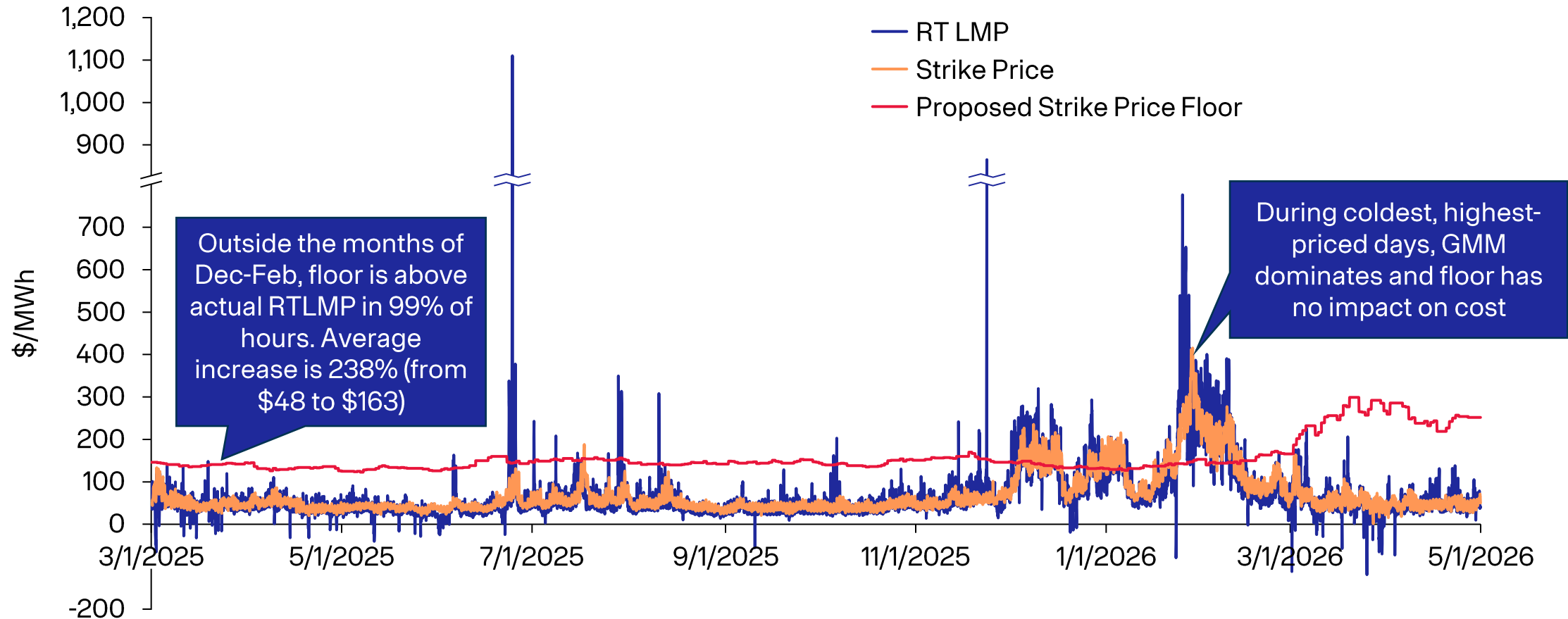
From Slide 16 of ISO-NE [presentation](#) at May 2026 MC



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.



M E M O R A N D U M

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.