PUBLIC VERSION

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Constellation Mystic Power, LLC	)	Docket No. ER18-1639-000

INITIAL BRIEF OF THE
NEW ENGLAND STATES COMMITTEE ON ELECTRICITY

Dated: November 2, 2018

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GLOSSARY

AFRR	Annual Fixed Revenue Requirement
Agreement	Cost-of-Service Agreement
ARGA	Amended and Restated Firm Gas Sales and Purchase Agreement
ASC	Accounting Standards Codification
CIP	Critical Infrastructure Protection
Connecticut Parties	Connecticut Public Utilities Regulatory Authority, Connecticut Department of Energy and Environmental Protection, and the Connecticut Office of Consumer Counsel
Commission or FERC	Federal Energy Regulatory Commission
CWC	Cash Working Capital
DOMAC or Distrigas	Distrigas of Massachusetts LLC
ENECOS	Eastern New England Consumer-Owned Systems
EDIT	Excess Deferred Income Taxes
Engie	Engie Gas & LNG Holdings LLC (Engie)
Everett or EMT	Everett Marine Terminal
Exelon	Exelon Corporation
ExGen	Exelon Generation Company, LLC
Exh.	Exhibit
FPA	Federal Power Act
FSA	Fuel Supply Agreement
GAAP	Generally Accepted Accounting Principles
Hearing Order	*Constellation Mystic Power, LLC*, 164 FERC ¶ 61,022 (2018).
ISO-NE or the ISO	ISO New England Inc.

LNG	Liquefied natural gas
MISO	Midcontinent Independent System Operator, Inc.
MISO Clawback	MISO, FERC Electric Tariff, Module C, § 38.2.7e
MISO Order	*Midcontinent Independent System Operator, Inc.*, 161 FERC ¶ 61,059 (2017)
Mystic	Constellation Mystic Power, LLC
Mystic 8 & 9 or Mystic Units	Mystic 8 and 9 units
NERC	North American Electric Reliability Corporation
NERC-CIP Incremental Capex	Capital expenditures related to compliance with North American Electric Reliability Corporation
NESCOE	The New England States Committee on Electricity
NESCOE Revisions	NESCOE proposed revisions to Schedule 3A, Attachment C
NYISO	New York Independent System Operator
NYISO Clawback	NYISO, Market Administration and Control Area Services Tariff, Rate Schedule 8, § 15.8.7
NYISO Order	*New York Independent System Operator, Inc.*, 161 FERC ¶ 61,189 (2017)
PJM	PJM Interconnection, L.L.C.
PJM Clawback	PJM Interconnection, L.L.C., Intra-PJM Tariffs, Open Access Transmission Tariff, § 118
Presiding Judge	Presiding Administrative Law Judge
Procedural Order	*Constellation Mystic Power, LLC*, Docket No. ER18-1639-000, Order Establishing Procedural Schedule and Rules of Procedure for Hearings (July 27, 2018)
ROE	Return on Equity
Sellers	DOMAC, and ENGIE Gas & LNG LLC
SVC	Stipulated Variable Cost

Tr.	Transcript
Transmittal Letter	*Constellation Mystic Power, LLC,* Transmittal Letter, Docket No. ER18-1639-000 (May 16, 2018)
USoA	Uniform System of Accounting

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Pursuant to Rule 706 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("FERC" or "Commission"),[1] the Commission's July 13, 2018 order in the above captioned proceeding ("Hearing Order"),[2] and the Presiding Administrative Law Judge's ("Presiding Judge") July 27, 2018 Order Establishing Procedural Schedule and Rules of Procedure for Hearing ("Procedural Order"), the New England States Committee on Electricity ("NESCOE") respectfully submits its initial brief.

STATEMENT OF THE CASE

The question before the Commission is whether the proposed cost-of-service agreement ("Agreement") submitted by Constellation Mystic Power, LLC ("Mystic") is just and reasonable.[3] That is—the Commission must determine if the rates, terms and conditions of the Agreement are just and reasonable. The Agreement as filed is not. It contains a number of provisions that are favorable to Mystic and Exelon Generation Company, LLC ("ExGen")[4] and that impose undue risks and excessive cost on consumers, while lacking transparency in certain fundamental respects.

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1 18 C.F.R. § 385.706.

2 *Constellation Mystic Power, LLC,* 164 FERC ¶ 61,022 at P 12 (2018).

3 The Agreement has been submitted by Mystic as Exh. MYS-0080.

4 Mystic and ExGen are both subsidiaries of Exelon Corporation ("Exelon") and are referred to collectively, herein, as Exelon.

This outcome is not at all surprising. The counterparties to the Agreement—Exelon and ISO New England Inc. ("ISO-NE" or the "ISO")—did not view themselves as having an obligation to protect customers. Exelon's fiduciary responsibility in negotiating the Agreement was, of course, to its shareholders.[5] Mystic witness William B. Berg asserts, mistakenly, that consumer interests had been previously addressed because Exelon negotiated the Agreement with ISO-NE:

> I believe that intervenors have lost sight of the fact that the Mystic Agreement, and the decisions about how to incentivize desired operations of Mystic and Everett, were made on a negotiated basis, with the active participation and agreement of ISO-NE – the *Independent* System Operator – except as to the amount of the rate to be charged. This contrasts with a typical [Federal Power Act ("FPA")] Section 205 filing where the seller of FERC jurisdictional services submits its unilateral view of a just and reasonable rate without the input, negotiation, and ultimate agreement from a not-for-profit, third-party with a mandate to protect reliability and the integrity of the market.[[6]]

Mystic fundamentally ignores the fact that ISO-NE "did not perform a formal analysis of the means to reduce costs of the . . . Agreement to consumers."[7] ISO-NE further states that it "has taken no position on the components of the agreement that address Exelon's revenue requirements and expected this aspect of the agreement to be resolved in this proceeding."[8] Mystic also ignores the fact that there was no negotiation between Mystic and any representatives of load or customers regarding the rates to be charged and risks passed onto consumers under the Agreement[9] and that ISO-NE acknowledged **[BEGIN CUI/PRIV]**

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5 Tr. 665:15-18.

6 Berg Rebuttal, Exh. MYS-0025 at 2:6-14 (emphasis in original).

7 Exh. NES-003 at 1.

8 *Id.*

9 Tr. 665:8-14 (Berg).

[redacted][10] **[END CUI/PRIV]** Mystic's view is that the process of intervenors analyzing and recommending changes to the Agreement "totally bypasses and gives no weight to the substantial give and take of the negotiation process that has already occurred" and that it is not "appropriate or reasonable."[11] Essentially, Mystic would like intervenors to defer to the negotiations it had with ISO-NE while ISO-NE, in those negotiations, explicitly **[BEGIN CUI/PRIV]** [redacted] **[END CUI/PRIV]** In arriving at an outcome that is just and reasonable, seeking deference to these negotiations is an unfair and impossible ask. The Commission must not countenance this view of the process and must not cater to Mystic's threats that if it does not get everything it wishes for its shareholders, it will retire.[12]

The Commission's statutory obligation is to ensure that the rates, terms, and conditions of this Agreement are just and reasonable. NESCOE urges the Commission to exercise this statutory authority in a straightforward way, and not in a way that calls for guessing what it might take to keep Mystic from announcing retirement of the Mystic 8 and 9 units ("Mystic 8 & 9" or "Mystic Units"). Instead, as discussed below, NESCOE respectfully asks the Commission to direct changes to the Agreement to rebalance a negotiation process that was flawed from its outset and that left consumer economic interests to litigants in this proceeding and to the Commission. It takes only a little digging below the surface to expose the rotted roots of the negotiated terms.

Mystic proposes that consumers pay over $550 million to keep the Mystic Units running for two years and exposes consumers to unknown and unquantifiable management costs under

10 Exh. NES-049 at 13.

11 Berg Rebuttal, Exh. MYS-0025 at 2:22-24.

12 *See* Tr. 665:23 – 666:11 (Berg); Exh. MYS-0025 at 3:6-12.

the Amended and Restated Fuel Supply Agreement ("FSA").[13] Mystic's proposed charges are excessive. As the record reflects, the Agreement substantially overstates the rate base for both Mystic 8 & 9 as well as for the Everett Marine Terminal ("Everett" or "EMT"). The Mystic Units have been participating in the ISO-NE wholesale markets for over 15 years and have had every opportunity to earn revenues that are not limited by a cost-of-service structure. Despite **[BEGIN CUI/PRIV-HC]** [redacted] **[END CUI/PRIV-HC]**, Mystic now refuses to apply a current impairment analysis to the two units for which it seeks cost-of-service rates. Customers should only pay a return on what the investment value of the Mystic Units is today, and NESCOE urges the Commission to reduce the rate base of the Mystic Units accordingly.

Mystic seems to contend that the purpose of the Agreement is to enable it to recover costs that it would incur specifically because of a decision to keep the units running for two more years.[14] Yet, the record shows that over half of the revenue requirement that Mystic seeks to recover is not for costs it would expend in the cost-of-service period, *i.e.*, June 1, 2022 to May 31, 2024. The Commission should disregard Mystic's dramatic characterizations and focus on the nuts and bolts of what the value of the rate base is today.

In an unusual gambit, Mystic seeks also to recover the full cost-of-service for the liquefied natural gas ("LNG") facility that its affiliate, ExGen, recently acquired from Distrigas of Massachusetts LLC ("DOMAC" or "Distrigas"). However, the record demonstrates that the rate base for Everett is significantly inflated because Mystic has failed to justify **[BEGIN**

[13] The original Fuel Supply Agreement was included as Exhibit MYS-0004; however, all references herein are to the Amended and Restated Fuel Supply Agreement included as Exhibit MYS-0016.

[14] *See, e.g.*, Exh. MYS-0025 at 9:6-7 ("much of the rest of the amount of the rate will simply be recoupment of expenses that we would not incur but for a decision to continue operating.").

CUI/PRIV-HC] [redacted] **[END CUI/PRIV-HC].**[15] Under both the Commission's Uniform System of Accounting ("USoA") rules and Generally Accepted Accounting Principles ("GAAP"), the impairments taken on the Distrigas facility's books should have been reflected, and the record demonstrates that the rate base for Everett should be set at zero.

Making matters worse, Mystic disregards Commission precedent when it fails to propose a "clawback" mechanism to ensure that capital expenditures and significant repairs that consumers fund are returned if the facilities seek to remain in the market beyond the two-year cost-of-service term. Although Mystic suggested in its May 16 filing that it would be willing to consider a "clawback" mechanism ("Mystic is willing, . . . provide a "clawback" process to refund certain capital expenditures incurred during the reliability term if the units remain in service past the termination date"),[16] it now seeks to drastically limit the circumstances under which it would consider refunding consumers' money. In particular, Mystic would not agree to refund customers' money if ISO-NE were to develop a long-term fuel security solution and Mystic were to reenter the market.[17] Of course, Mystic knows the Commission ordered ISO-NE to develop a long-term fuel security solution and that ISO-NE is in the process of developing new market rules. Mystic's proposed limitation is antithetical to the Commission's anti-toggling policies, and to what is fair to customers. Mystic wants to capture for its shareholders all the benefits of pretending, for accounting purposes, that the Mystic Units had operated under cost-of-service rates from their inception, while ignoring the earnings opportunities its shareholders

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[15] *See* Heintz Supplemental Testimony, Exh. MYS-0020 at 9:15-16.

[16] *Constellation Mystic Power, LLC*, Transmittal Letter, Docket No. ER18-1639-000, at 16 (May 16, 2018) ("Transmittal Letter").

[17] Exh. MYS-0053 at 38:4-6 ("The claw back provision should be triggered only in the circumstance where no market fix is implemented or Mystic is ineligible for fuel security revenues, but Mystic nonetheless elects to return to the market.").

had for a decade and a half when the resources were merchant plants. Then, if the market reflects a more favorable environment at the end of the Agreement term, Mystic wants to go back to reaping the reward for shareholders that a merchant plant may provide, with no refund of consumer dollars for improvements to its facilities. As Mystic twists and turns through regulatory frameworks to maximize shareholder profits, ratepayers necessarily come up on the short end at each step. The Commission should reject this ploy.

Mystic's contention that ISO-NE's participation in the negotiation ensured fairness to consumers (*see* supra at p. 2) is contradicted by ISO-NE itself. ISO-NE understood its proposed changes to its *pro forma* cost-of-service agreement[18] (referred to herein as the "*pro forma*") would have cost implications that it explicitly deferred to litigants.[19] ISO-NE's choice not to concern itself with consumer cost considerations means that a number of provisions to the Agreement must now be changed to achieve a just and reasonable outcome, not one that only benefits Exelon shareholders. NESCOE urges the Commission to direct Mystic to modify the Agreement as NESCOE describes below.

Moreover, as the record in the proceeding reflects, there is and has been an information mismatch. The information "black box" favors Mystic as the party with the information. Mystic's proposal would extend this mismatch into the cost-of-service period by establishing a true-up process that hardwires a "transparency lag" discussed below and would not allow customers the ability to review capital expenditures on an ongoing basis. Rather, Mystic's process would require customers to review several years' worth of data all at once and in a short

[18] The ISO *pro forma* cost-of-service agreement is found at ISO-NE FERC Tariff No. 3, Market Rule 1, Section III, Appendix I.

[19] Exh. NES-003 at 1 ("ISO-NE did not perform a formal analysis of the means to reduce costs of the Mystic Cost of Service Agreement to consumers. ISO-NE has taken no position on the components of the agreement that address Exelon's revenue requirements and expected this aspect of the agreement to be resolved in this proceeding.").

period of time prior to the opportunity to challenge such costs. Furthermore, the challenge process, while improved compared to Mystic's initial proposal, still contains roadblocks to transparency and suffers from a lack of clarity in some areas.

Additionally, Mystic's true-up process should not be a shield to recover certain costs that are inappropriate for recovery. These include the costs that Mystic is incurring to move the auxiliary boiler from the Mystic 7 site **[BEGIN CUI/PRIV-HC]** [redacted] **[END CUI/PRIV-HC]**; property tax costs related to Mystic 7, some of which should be appropriately allocated to Mystic shareholders; and costs of changing the designation of the Mystic Units under the North American Electric Reliability Corporation ("NERC") standards to a medium impact classification, when that classification is not related to the cost-of-service period and when ISO-NE has not designated those units as necessary to avoid an "Adverse Reliability Impact" in the long-term planning horizon or for any other reason.

The Commission must also ensure that there are meaningful opportunities for states and other consumer-interested parties to review, assess, and provide input on the operations and costs in connection with the Mystic Units and EMT. The Agreement seeks to impose hundreds of millions of dollars in costs on consumers, and its execution requires oversight commensurate with the level of consumer risk and cost exposure.

Finally, but critically, the Commission must ensure that the terms and conditions of the FSA are just and reasonable. Putting aside the question of whether the FSA itself is subject to FERC's jurisdiction, costs under the FSA flow through the Agreement to customers and therefore the Commission must ensure that such charges are just and reasonable. As presented in NESCOE's testimony, there are significant flaws with the FSA structure, and the Commission should not find it just and reasonable to pass its costs through the Agreement. Under the FSA as proposed, Exelon's subsidiary would have no incentive to manage EMT effectively, resulting in excessive cost passed through to customers and harm to regional gas and electric markets. NESCOE's witness presented an alternative approach to the FSA structure that has the following advantages:

- It reflects a simpler and more common and sensible fuel supply contract structure, focused only on the service to Mystic;
- It follows the common straight fixed variable rate design (demand charge, commodity charge), and uses other contract provisions common in the industry;
- It leaves Constellation LNG, the marketer/operator of Everett, with the opportunity and full incentive to profit from managing the Everett facility effectively and providing valued services to other customers;
- It imposes the actual costs and risks associated with managing Everett (tank management, cargo scheduling) on Constellation LNG, the party in the best position to manage these costs and risks;
- It affords Constellation LNG the needed flexibility to use Mystic dispatch to manage tank levels, while holding Constellation LNG accountable for the actual costs of such actions;
- It provides Constellation LNG the same incentives to achieve fuel security, and imposes appropriate consequences on Constellation LNG for failing to achieve fully reliable fuel supply; and
- It compensates Constellation LNG (in expectation, through the Reliability Charge) for taking on the challenges of providing reliable and flexible service, and for the associated costs and risks.

Ultimately, this approach would result in more efficient operation of the Everett facility and lower costs imposed on customers through the Agreement, maintaining fuel security while mitigating other stakeholders' concerns of market power and market interference.

PROCEDURAL HISTORY

NESCOE adopts the Joint Statement of Procedural History submitted by the parties to the Presiding Judge on October 11, 2018.

ARGUMENT

I. THE RATE TO BE COLLECTED UNDER THE MYSTIC COST-OF-SERVICE AGREEMENT IS NOT JUST AND REASONABLE.

A. The Proposed Calculation of Non-Fuel Costs Is Not Just and Reasonable.

1. The Proposed Annual Fixed Revenue Requirement ("AFRR") for Mystic 8 & 9 Is Not Just and Reasonable.

a. The Proposed Rate Base for Mystic 8 & 9 Is Not Just and Reasonable.

The proposed rate base for Mystic 8 & 9 is not just and reasonable. Rather, for the reasons discussed below, the proposed rate base for Mystic 8 & 9 is substantially overstated. The Commission should reject Mystic's proposed rate base for the Mystic Units.

i. The proposed gross and net plant values used in the proposed AFRR for Mystic 8 & 9 are not just and reasonable.

NESCOE's request to the Commission is based on a simple but important premise. The Mystic Units must be valued *based on conditions as they exist today*. Consumers should not be forced to pay excessive rates to make up for Mystic's past investment decisions or decisions it would make differently today with the benefit of hindsight, to harmonize complicated and confusing accounting rules, account for long-term contractual buyouts and mergers, or reliance on the value of other assets that its parent, Exelon, owns. Allowing Mystic to value its cost-of-service assets in this manner would encourage additional resources to seek to leave the wholesale markets during periods of time when they view those markets negatively and remain in operation through cost-of-service rates. Under Mystic's logic, these resources could be treated as if they were cost-of-service units from their inception for purposes of determining their rate base values. Such an approach would undermine a primary premise why states restructured the electric markets to a competitive framework, which was to shift investment risk onto investors and away from consumers.[20] The Commission must ensure that the value of the Mystic Units, upon which consumers will be required to pay a return, are appropriately based on the conditions as they exist today, and not on conditions Mystic has speculated to exist or to have existed.

(a) Mystic's approach to expected cash flows skews the value of the Mystic Units.

As an initial matter, Mystic seeks to recover the full net plant value without taking into consideration any impairments. According to Mystic, the rate base for Mystic 8 & 9 appropriately reflects net plant, *i.e.*, the gross plant value less accumulated depreciation, plus capital expenditures. Mystic witness Alan C. Heintz determined a gross plant value in the amount of $1,021,103,939,[21] with $167,698,415 in depreciation reserve, for a net plant value of $853,405,553.[22] Mr. Heintz states that the gross plant values are based on the purchase price of Mystic 8 & 9.[23]

However, the net plant value of $853 million does not take into consideration any impairment charges for Mystic 8 & 9. As NESCOE witness Jeffrey W. Bentz testified, consumers should not be responsible for paying an equity return on the full value that Mystic reported as net plant.[24] Mystic's contention that an impairment charge is not required is wrong.[25]

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[20] *See* Reishus Consulting, LLC, *Electric Restructuring in New England – A Look Back*, prepared for NESCOE, at 2, 7-8, 21 (Dec. 2015), available at http://nescoe.com/wp-content/uploads/2015/12/RestructuringHistory_December2015.pdf ("*Electric Restructuring*").

[21] Exh. MYS-0020 at 8:23; Exh. MYS-0008.

[22] Exh. MYS-0020 at 8:22-24.

[23] *Id*. at 9:6-7.

[24] Bentz Testimony, Exh. NES-001 at 29:10-11.

As discussed below, Mystic's responses to questions concerning impairment have been cryptic and confusing. Record evidence shows that Mystic either performed a stand-alone impairment for the Mystic Units and it yielded **[BEGIN CUI/PRIV-HC]** [redacted] **[END CUI/PRIV-HC]** or that it never performed a stand-alone impairment assessment in the first place. Either way, Mystic has failed to demonstrate a basis for its asserted net plant value for Mystic 8 & 9.

In the course of discovery, NESCOE attempted to determine whether Mystic had conducted an impairment assessment on Mystic 8 & 9. One response that Mystic provided to NESCOE appeared to be such an analysis. The analysis showed that **[BEGIN CUI/PRIV-HC]** [redacted][26] **[END CUI/PRIV-HC]** At the hearing, Mystic witness Mr. Berg, who was shown as the sponsor of this analysis, **[BEGIN CUI/PRIV-HC]**[27] [redacted] **[END CUI/PRIV-HC]**

25 Exh. NES-004 at 4-5.

26 *Id* at 4; Exh. NES-007 at 1-4.

27 Where NESCOE refers to material from the confidential sessions of the hearing, NESCOE uses the designation "CUI/PRIV-HC" although that is not the designation used in the hearing transcripts; they are merely marked "confidential."

28 *See* Exh. NES-004 at 4.

29 Tr. 673:2 – 674:1.

Mystic's earlier discovery responses indicated that it did not perform a stand-alone impairment analysis for Mystic 8 & 9.[30] Mystic instead defended its conclusion that no impairment charge was necessary because Exelon's group of New England assets showed positive cash flows into the future based on long-term market rule changes. In a 2018 quarterly report, Exelon stated that it conducted a "comprehensive review of the estimated undiscounted future cash flows of the New England asset group during the first quarter of 2018" and concluded that "no impairment charge was required."[31] In response to NESCOE's inquiry, Mystic confirmed that Exelon groups its assets by region in performing impairment analyses, and that no impairment charge was taken "because the estimated undiscounted cash flows for the New England Asset group were greater than the book value."[32] The response emphasized that "the analysis assumed that a long-term solution *would be* implemented in New England that would make Mystic 8 and 9 economic for its remaining useful life" and noted that "failure of ISO-NE to adopt interim and long-term solutions for reliability and fuel security could potentially result in future impairments of the New England asset group."[33]

Mystic's response to a follow-up discovery request suggested some confusion about the analysis. Mystic **[BEGIN CUI/PRIV-HC]** [redacted][34] **[END CUI/PRIV-HC]** However, Mystic witness Mr. Berg

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30 Exh. NES-004 at 4.

31 *Id*.

32 *Id*. at 4-5.

33 *Id*. at 5 (emphasis supplied).

34 Exh. NES-043 at 1 (emphasis supplied). However, in the very same response, Mystic stated that **[BEGIN CUI/PRIV-HC]** [redacted]

confirmed at the hearing that Exelon's asset group impairment analysis assumed that fuel security *would* be valued in the ISO-NE markets.[35] Mystic's witnesses also acknowledged that as of the date of the hearing, ISO-NE had proposed no such long-term solution,[36] undercutting the premise for its "no impairment" conclusion. The impairment assessment cannot and should not assume a market "fix" because it is unknown what this solution will be; if and when it will be implemented; and even if implemented, whether it will provide any additional value to Mystic.

Because Mystic is seeking approval for a cost-of-service agreement *solely* for Mystic 8 & 9, Mystic should have performed a stand-alone impairment assessment for those assets to develop an accurate value for these units on which consumers are being asked to provide a return. Mystic is not seeking recovery under the Agreement for all of Exelon's New England Assets, and an impairment assessment on that whole grouping is inappropriate.[37] Moreover, as explained in a Deloitte report on impairment, to test for impairment of an asset or asset group that is held and used, a utility should compare future cash flows from the use and ultimate disposal of the asset or asset group with the carrying amount of the asset or asset group.[38] "Impairment exists when the expected future nominal (undiscounted) cash flows, excluding interest charges, are less than the carrying amount."[39]

In the absence of any such stand-alone impairment analysis, Mystic has not demonstrated that it is entitled to earn a rate of return based on the full investment value of Mystic 8 & 9,

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[redacted] **[END CUI/PRIV-HC].**

35 Tr. 670:8-15.

36 Tr. 670:16-20.

37 Bentz Testimony, Exh. NES-001 at 31:8-10.

38 Exh. NES-026 (Deloitte, Power and Utilities, Accounting, Financial Reporting, and Tax Update, January 2016).

39 Exh. NES-021 at 6:13-7:2; *see also* Exh. NES-026 at 4.

rather than on the impaired value of those units.[40] Indeed, there is evidence in the record that **[BEGIN CUI/PRIV-HC]** [redacted] **[END CUI/PRIV-HC]**.[41] This should be sufficient justification for the Commission to, at a minimum, direct Mystic to perform an impairment assessment for Mystic 8 & 9 on a stand-alone basis and reduce the net plant for rate base by that amount.[42] This would not place a great burden on Mystic, **[BEGIN CUI/PRIV-HC]** [redacted][43] **[END CUI/PRIV-HC]** If any such burden does exist, it is dwarfed in comparison to the burden on ratepayers if Mystic does not conduct a proper impairment analysis.

Mystic also asserts that it should not be required to make impairment adjustments because the accounting rules would "work an unwarranted hardship."[44] Mystic further contends that "the impairment is not related to the unit's condition, but outside market forces,"[45] and that had the units been under cost-of-service regulation, there would not have been an impairment in the first instance due to the decrease in the market price.[46] This ignores, of course, that had the units been under cost-of-service regulation shareholders would not have benefitted from the opportunity to earn unlimited returns.[47]

Mr. Heintz further states that:

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[40] *See* Bentz Testimony, Exh. NES-001 at 31:12-14.

[41] Steffen Testimony, Exh. ENC-0030 at 59:1-10.

[42] Exh. NES-001 at 32:1-6.

[43] *See* Exh. NES-007 at 1-8.

[44] Heintz Rebuttal Testimony, Exh. MYS-0037 at 5:17-18.

[45] *Id*. at 6:17.

[46] Exh. MYS-0037 at 6:20-22.

[47] *See, e.g.*, Tr. 300:14-15 ("Do I have any belief that the cost-of-service rates would be the same as the market rates? No, I don't.").

> if the purpose of developing a cost of service rate for the unit is to provide for the continued operation of the unit due to the inability of the market to provide sufficient revenues, then recognizing an impairment resulting from insufficient revenue recovery creates a 'Catch 22': the accounting adjustment would embed the market failure into the cost of service rate, and so defeat the purpose of developing a cost of service rate as an alternative to the market rate.[[48]]

However, at the hearing, Mr. Heintz confirmed that the cases he cited in support of his "Catch 22" argument were all reactive power cases, none of which involved a reliability must-run generator; none of which involved a situation where a generator is seeking to have costs of an LNG facility that it has purchased included in the cost; and none of which involved valuation of generation plants.[49]

Moreover, Mystic misses the point of the inquiry. The point is about getting to the proper rate base value for the assets today under the Agreement through which Mystic seeks to recover costs from consumers. It is not whether or not the market has worked to produce revenues satisfying to Mystic and not what the plant value "would had been if" conditions had been different than what they actually were. To value the assets correctly, Mystic cannot divorce its analysis from the expected cash flows of the Mystic Units *based on conditions as they exist today*. And, as noted above, the expected cash flows of the units based on conditions as they exist today are **[BEGIN CUI/PRIV-HC]** [redacted] **[END CUI/PRIV-HC]**[50]

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[48] Exh. MYS-0037 at 7:4-11.

[49] Tr. 300:23 – 301:9.

[50] Exh. NES-007 at 1-4; Tr. 676:13-21.

(b) The proposed accumulated depreciation is not just and reasonable.

The amount of accumulated depreciation reserves that Mystic subtracts from its gross plant value is understated; **[BEGIN CUI/PRIV-HC]** [redacted][53] **[END CUI/PRIV-HC]**

Mystic's complaint that it would not have needed to take an impairment write-off if the units had been under cost-of-service regulation[54] cannot be reconciled with its treatment of the accumulated depreciation reserves. If Mystic wants Mystic 8 & 9 to be treated like cost-of-service regulated units, and not have to take an impairment charge, then it needs to account for depreciation of the resources over their entire useful lives. It cannot remove **[BEGIN CUI/PRIV-HC]** [redacted] **[END CUI/PRIV-HC]** from the rate base calculation.

(c) Mystic's request for full cost of service fails to account for expenses it will incur irrespective of a cost-of-service Agreement.

Mystic's request for full cost of service overstates the cost recovery to which it is entitled. Mr. Berg threatened in his rebuttal testimony that "[e]very dollar will count in that analysis, especially the dollars flowing from the return, since much of the rest of the amount of the rate will simply be recoupment of expenses that we would not incur but for a decision to continue

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51 Tr. 230:24-231:3. *See also* Exh. ENC-0067.

52 Tr. 232:1-7.

53 Tr. 232:13-16.

54 Exh. MYS-0037 at 6:20-22.

operating."[55] Mystic's implication, in other words, is that the Company is primarily trying to recoup only costs it would incur during the cost-of-service period to keep the units operating. This is not an accurate characterization.

For Mystic 8 & 9 alone, Mystic is requesting to recover $136 million in return on equity[56] and $72 million in depreciation expense.[57] These amounts represent slightly higher than one-half of Mystic's total request and neither requires additional cash outlays during the cost-of-service period.

In addition, there are significant costs for which it seeks recovery under the Agreement that Mystic would incur even if it were to retire in 2022. In particular, **[BEGIN CUI/PRIV-HC]** [redacted] **[END CUI/PRIV-HC]** The Commission should recognize that Mr. Berg's ultimatum regarding "every dollar" may not be the firm line in the sand it portends to be.

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55 Exh. MYS-0025 at 9:4-7.

56 This amount is derived from Exh. MYS-0050 at 1, Schedule A taking 7/12th of line 22 for 2022 + line 22 for 2023 + 5/12th of line 22 for 2024.

57 This amount is derived from Exh. MYS-0050 at 1, Schedule A taking 7/12th of line 17 for 2022 + line 17 for 2023 + 5/12th of line 17 for 2024.

58 Tr. 676:7-9. *See also* Exh. ENC-0085 at 4.

59 Exh. ENC-0085 at 4; Tr. 678:24-679:11.

60 **[BEGIN CUI/PRIV-HC]** [redacted] **[END CUI/PRIV-HC]**

It is critical that the Commission ensure that the rate base is not inflated. In order to do so, the Commission must, as NESCOE recommends, direct Exelon to undertake a stand-alone impairment assessment of Mystic 8 & 9 and reduce the rate base accordingly upon the findings of the assessment. The Commission should not be rattled by Mr. Berg's statement that the "inability to recover anything close to its full cost-of-service, are non-starters and also lead me to recommend retirement."[61] The Commission should be concerned with establishing a just and reasonable rate, and an integral part of that is setting an appropriate rate base. If that just and reasonable rate is unacceptable to Mystic, then it simply is unacceptable, and Mystic will determine its future accordingly and the region will react in order to bring on other resources accordingly. For the Commission to set rates at anything beyond a just and reasonable level due to Mr. Berg's representations about his intended recommendations would invite a parade of other resources seeking to inflate their returns by leaving the wholesale market and obtaining padded cost-of-service agreements.

ii. There should be a reduction in the Mystic Units' rate base to reflect excess deferred income taxes ("EDIT").

In its application, Mystic did not include a deferred regulatory liability for any EDIT related to Mystic 8 & 9. As NESCOE's witness Connie T. Cannady explained, Mystic had not reflected any changes to the accumulated deferred balances that existed on the books of either Mystic 8 & 9 or Everett as of December 31, 2017 and had not included any amortization of EDIT that exists on the books of Mystic (or its parent) as a regulatory liability.[62] In response to discovery requests, Mystic confirmed that it did not recognize any change in the EDIT and

[61] Exh. MYS-0025 at 3:11-12.

[62] Cannady Testimony, Exh. NES-010 at 19:7-10.

indicated it did not anticipate recognizing any EDIT in any of the years 2017 through 2025 for purposes of establishing the revenue requirements.[63]

However, Mystic has since conceded that there should be a change in the EDIT. Specifically, in his rebuttal testimony, Mystic witness Mr. Heintz agreed that the cost-of-service calculation should include a reduction to rate base for a regulatory liability reflecting the net EDIT, to be amortized beginning January 1, 2018, over the Mystic Units' remaining depreciable life.[64] Mr. Heintz provided a revised cost-of-service calculation, Exhibit MYS-0050, that includes a reduction in the tax allowance for the EDIT amortization, grossed up for taxes in the amount of $2,038,678.[65] The Commission should accept this aspect of Mystic's revised filing so that the rate base is appropriately reduced to reflect EDIT.

iii. The proposed cash working capital ("CWC") for the Mystic Units is not just and reasonable and should be set to zero.

Mystic proposed to use one-eighth of annual operations and maintenance ("O&M") expenses as a default value for cash working capital for Mystic 8 & 9.[66] Mystic has not supported its use of one-eighth of its O&M expenses as CWC in this case, and the Commission should disallow the inclusion of CWC requested from 2017 through the cost-of-service period for Mystic 8 & 9. Although the Commission may accept one-eighth of annual O&M expenses in lieu of a lead/lag study, Exelon has provided no explanation for why an electric utility its size would not have such a study available.

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[63] *Id.* at 20:11-13; *see also* Exh. NES-014 at 5.

[64] *See* Exh. MYS-0037 at 19:10-15.

[65] Exh. MYS-0050 at 1.

[66] Heintz Direct Testimony, Exh. MYS-0006 at 9:5-8; *see also id.* at 7:24 – 8:2, 12:15-16.

The one-eighth methodology is not appropriate in this circumstance. This method was originally developed as a proxy in the utility industry for determining CWC in the 1930s when lead/lag studies were burdensome to perform, particularly prior to the advent of personal computers.[67] Additionally, Mystic's proposed use of the one-eighth method does not take into account all of its costs and the revenue timing differences under the special circumstances in this case. In particular, as explained in Ms. Cannady's testimony, Mystic's request to expense all capital expenditures for Mystic 8 & 9 during the cost-of-service period greatly enhances Mystic's cash flow during this period.[68] Mystic has not adequately explained the absence of a lead/lag study, which would "develop both lead days and lag days due to the timing of expenses and receipt of payment for those expenses. . . and would be based on a sampling of the actual invoices paid by a company and the timing of how these costs are included in recovery from rates."[69] In the absence of a reliable lead lag study that recognizes the increased cash flow from expensing all capital expenditures during the cost-of-service period, the CWC should be set at $0 from 2017 through and inclusive of the cost-of-service period and should not be a component of any true-up established in the proceeding,[70] particularly given the unprecedented level of and nature of the costs Mystic seeks to recover from consumers.

The impact of Mystic's use of the one-eighth method for computing CWC results in an increase in the revenue requirement during the cost-of-service period of approximately $2.4

67 Cannady Testimony, Exh. NES-010 at 6:19-7; *see Interstate Power Co.*, 2 F.P.C. 71, 85 (1939).

68 Cannady Testimony, Exh. NES-010 at 8:7-9:12; *id.* at 9:7-9.

69 *Id.* at 10:11-14; *see also* Exh. NES-014 at 1.

70 Exh. NES-010 at 9:17-21.

million for Mystic 8 & 9.[71] The Commission should direct Mystic to set CWC at zero and remove the CWC from the Mystic Units' rate base.

b. The Proposed Weighted Average Cost of Capital for Mystic 8 & 9 Is Not Just and Reasonable.

i. The proposed return on equity is not just and reasonable.

Mystic has not demonstrated that its proposed return-on-equity ("ROE") is just and reasonable. In contrast, the record in this proceeding establishes that the ROE should be significantly lower than what Mystic requests.[72] The record evidence should lead the Commission to lower the ROE appropriately. Adoption of the Connecticut Parties'[73] ROE recommendation would achieve that end. NESCOE urges the Commission to give this recommendation as well as Ms. Cannady's perspective on a double leverage capital structure (discussed below in Section I.A.1.b.ii) considerable weight in its final determinations.

ii. The proposed capital structure is not just and reasonable.

With respect to capital structure, there is a fundamental mismatch in Mystic's ROE analysis. Ms. Cannady, NESCOE's witness, explained this mismatch in her testimony:

> ExGen does not issue stock and, therefore, its reported common equity is based on an infusion from its parent, Exelon Corporation. Dr. Olson recognizes this fact in his analysis of return on equity, by using Exelon Corporation stock information when comparing Exelon with other selected utility companies. . . .The results of Dr. Olson's analysis and recommendations are to include a capital

[71] *Id.* at 6:1-3; Exh. NES-013 at 1.

[72] Answering Testimony and Exhibits of David C. Parcell on Behalf of the Connecticut Public Utilities Regulatory Authority, the Connecticut Department of Energy and Environmental Protection, and the Connecticut Office of Consumer Counsel, Exhibits CT-001 through CT-009; Prepared Direct and Answering Testimony of Commission Trial Staff Witness Robert J. Keyton, Exhibits S-009 through S-0013; Prepared Answering Testimony of Jonathan A. Lesser on Behalf of Eastern New England Consumer-Owned Systems, Exhibits ENC-0001 through ENC-0023.

[73] Connecticut Public Utilities Regulatory Authority, Connecticut Department of Energy and Environmental Protection, and the Connecticut Office of Consumer Counsel.

> structure that has a significantly greater "equity" position than the company on which the ROE evaluation is based.[[74]]

Ms. Cannady further noted that, while Mystic has proposed an overall rate of return based on a capital structure of 32.7% debt and 67.3% equity, "Exelon Corporation's equity percentage has continued to decline from 2013 to 2017 but was never greater than 55.58% during this period."[75] In fact, Exelon had a capital structure that consists of roughly 52.38% debt and 47.62% equity as of June 2018.[76] Accordingly, Ms. Cannady concluded that Mystic's request for an ROE based on "an equity position that is over 41% greater than Exelon Corporation's is unreasonable and should not be approved."[77]

Ms. Cannady explained how Mystic can reconcile this mismatch in the capital structure used to perform the ROE analysis. She recommended using a double leverage capital structure. This approach accounts for "a utility [that] is owned by a parent company and the parent company obtains its funding through the issuance of debt and equity[.]"[78] In this circumstance, "double leveraging will occur when any of the parent funding is provided to its affiliate as equity."[79] As Ms. Cannady explained, "[t]he resulting capital structure of the affiliated utility is double leveraged because it has debt investors of its own and debt and equity investor funds from the parent, thus double leverage."[80]

In weighing the record evidence on ROE, the Commission should consider the double leverage capital structure approach. Alternatively, as Ms. Cannady recommended, if the

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74 Cannady Testimony, Exh. NES-010 at 21:10-16.

75 *Id.* at 21:4-5 – 22:1-3.

76 *Id.* at 21:18-19; Exh. NES-013 at 3; Exh. NES-019.

77 Cannady Testimony, Exh. NES-010 at 22:5-6.

78 *Id.* at 22:14-15.

79 *Id.* at 22:15-16.

80 *Id.* at 22:16-18. *See also, id.* at 23-25 for an example of this approach.

Commission does not adopt this approach, it should direct that Exelon's capital structure be set to 52.4% debt and 47.6% equity based on the June 2018 data.[81]

B. The Proposed Fuel Costs Are Not Just and Reasonable.

1. The Proposed Fixed O&M/Return On Investment Component of the Monthly Fuel Supply Cost Is Not Just and Reasonable.

a. The Proposed Rate Base For Everett Is Not Just and Reasonable.

The proposed rate base for Everett is not just and reasonable. At the outset, the proposed gross and net plant values for Everett included in the cost-of-service study are not just and reasonable. Mystic has not supported a rate base value of more than zero dollars, as discussed below, because, among other things, Mystic does not meet the Commission's two-prong substantial benefits test to **[BEGIN CUI/PRIV-HC]** [redacted] **[END CUI/PRIV-HC]**

i. The proposed gross and net plant values used for Everett are not just and reasonable.

Mystic's proposal to use $60 million as the gross plant value for rate base for EMT is not just and reasonable. Mystic proposes to include $60 million in rate base for EMT.[82] According to Mystic witness Mr. Heintz, "(t)he Gross and Net Plant for 2017 of $60 million **[BEGIN CUI/PRIV-HC]** [redacted] **[END CUI/PRIV-HC]**

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81 *Id.* at 25:14-16.

82 Exh. MYS-0008 at 15; *see also* Exh. MYS-0020 at 9:15; Exh. ENC-0069.

83 The transaction closed on October 1, 2018. Tr. 741:6-10.

84 Exh. MYS-0020 at 9:15-18.

NESCOE sponsored the testimony of Nancy Heller Hughes, an Accredited Senior Appraiser of public utility property certified by the American Society of Appraisers, and a Certified Depreciation Professional, certified by the Society of Depreciation Professionals.[85] As discussed in the answering testimony of Ms. Hughes, Mystic failed to provide adequate support to include in rate base **[BEGIN CUI/PRIV-HC]** [redacted] **END CUI/PRIV-HC]**.[87] The record evidence supports that the net plant value for EMT should be at or near zero.

By way of background, Mystic identified **[BEGIN CUI/PRIV-HC]** [redacted]

[redacted]

[redacted]

[85] Exh. NES-021 at 2:16-18; Exh. NES-022.

[86] *See* Exh. MYS-0020 at 9:15.

[87] Hughes Testimony, Exh. NES-021 at 4:19 – 5:2.

[88] *See* Exh. S-0030 (NES-MYS-1-74 and the attached documents entitled "CUI//PRIV-HC In-Tank Sale and Purchase"); Exh. S-0031 (NES-MYS-1-74 "CUI//PRIV-HC Disclosure Schedules to MIPA"); and Exh. S-0032 (NES-16 MYS-1-74 "CUI//PRIV-HC Membership Interest & Asset Purchase Agmt" ("MIPA")).

[89] *See* Exh. NES-024 at 1-2.

[90] Exh. NES-021 at 5:15-18.

[91] *Id*. at 6:7-8.

[92] *Id*. at 6:8-9.

[redacted][95] **[END CUI/PRIV-HC]**

In discussing his proposal that the rate base for Everett be set at the **[BEGIN CUI/PRIV-HC]** [redacted] **[END CUI/PRIV-HC]**[96] As Staff witness Janice Garrison Nicholas explains, however, it appears that Mr. Heintz was comparing the **[BEGIN CUI/PRIV-HC]** [redacted]

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93 *Id*. at 6:10-11.

94 *See* Exh. ENC-0030 at 66:3-10.

95 Exh. NES-021 at 8:1-4.

96 Exh. MYS-0020 at 9:15-18.

97 Exh. S-0025 at 11:15-16.

98 *Id*. at 12:2-6.

[redacted][99] **[END CUI/PRIV-HC]**

Furthermore, Ms. Hughes explained that, consistent with Accounting Standards Codification ("ASC") 60-10-35, to test for impairment of an asset or asset group that is held and used, a utility should compare future cash flows from the use and ultimate disposal of the asset or asset group with the carrying amount of the asset or asset group. Impairment exists when the expected future nominal (undiscounted) cash flows, excluding interest charges, are less than the carrying amount.[100] In other words, "a fair value write down occurs when it is determined that an asset has been impaired because its fair value is below its recorded cost. When an impairment occurs, the recorded cost of the asset is reduced by the amount of the impairment and the adjustment may be referred to as a fair value write down or an impairment loss."[101] Factors which can cause plant impairment include significant changes in the economic, technological, political or market environment in which the entity operates; decrease in demand; and decrease in fuel and energy prices.[102]

Exelon management was aware that **[BEGIN CUI/PRIV-HC]** [redacted]

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[99] *Id*. at 12:7-10.

[100] Exh. NES-021 at 6:13-7:2; *see also* Exh. NES-026.

[101] Exh. S-0025 at 12:14-13:2.

[102] Exh. NES-021 at 7:4-6.

[103] Exh. ENC-0085 at 3 (emphasis supplied).

[redacted][104] **[END CUI/PRIV-HC]**. Exelon provides no evidence to rebut that EMT's future nominal (undiscounted) cash flows, excluding interest charges, are less than the $60 million carrying amount. Like the overinflated value of the Mystic Units, Exelon seeks Commission approval to charge consumers a return on unjustified balances resulting from the investment choices others have made and, in the case of EMT, a shell game of contracts, discussed below, that benefit Exelon at consumers' expense.

Mystic takes the position that **[BEGIN CUI/PRIV-HC]** [redacted][105] **[END CUI/PRIV-HC]** This is not a broadly accepted view. Ms. Hughes refers, for example, to an accounting firm's report on impairment,[106] which expressly addresses regulated utilities recording plant impairment losses on their books:

> For regulated utilities subject to the provisions of ASC 980, ASC 360-10 does not specify whether an impairment loss should be recorded as a reduction in the asset's original cost or as an adjustment to the depreciation reserve. Adjustment to the original cost appears to be consistent with the notion that recognizing an impairment establishes a "new cost" for the asset. However, for enterprises that are subject to cost-based regulation and apply ASC 980, original historical cost is a key measure for determining regulated rates that may be charged to customers. Accordingly, rate-regulated enterprises may be directed by their regulators to retain original historical cost for an impaired asset and to charge the impairment loss directly to accumulated depreciation.[107]

Thus, for rate regulated utilities, plant impairment is, in fact, a form of depreciation as recognized by the FERC Uniform System of Accounts ("Depreciation, as applied to depreciable

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[104] *Id*. at 4.

[105] Heintz Supplemental Testimony, Exh. MYS-0020 at 9:18-19.

[106] Exh. NES-026.

[107] *Id*. at 4.

electric plant, means the loss in service value not restored by current maintenance, … Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and requirements of public authorities.”).[108] NESCOE notes that if Everett is treated as a regulated utility for cost-of-service treatment, it would be subject to USoA rules, as discussed in Ms. Hughes’ testimony. If Everett is treated as unregulated, it would be subject to GAAP rules, as discussed in Staff’s witness Ms. Nicholas’ testimony. Either way, the rate base value should be zero.

Additionally, as Mr. Steffen points out:

> **[BEGIN CUI/PRIV-HC]**
>
> [redacted]

[END CUI/PRIV-HC][109]

The various contractual arrangements relating to EMT confirm the fiction of valuing the asset at $60 million for rate base purposes. The **[BEGIN CUI/PRIV-HC]** [redacted]

[108] Exh. NES-021 at 8:10-15 (quoting 18 C.F.R. Part 101, Definition No. 12).

[109] Exh. ENC-0030 at 65:8-18.

[redacted]

[redacted]

[redacted]

110 *See* Exh. NES-023 at 7-8 (MIPA, Section 1.3).

111 The ARGA is appended to Mr. Schnitzer's Rebuttal Testimony as Exhibit MYS-0054.

112 *See* Exh. MYS-0054 at 24. Algonquin Citygates Index has historically tracked regional New England power prices, ensuring, over time, that the power generated by Mystic 8 & 9 can be done so at a profit. Additionally, since Mystic 8 & 9 rely exclusively on imported LNG for fuel, for the majority of the year, global LNG prices (using Dutch TTF as the proxy) are forecast to be significantly higher than the Algonquin Citygates Index. *See* Exh. NES-028 at 12, Figure JFW-1.

113 Tr. 495-497.

[redacted][114] **[END CUI/PRIV-HC]**

According to USoA rules, which appear to be applicable to this case rather than GAAP rules since Mystic is requesting cost-of-service treatment, when a utility acquires property, the value of the property that is recorded in plant in service on the books of the utility is recorded at original cost less depreciation including impairment. Any amount paid in excess should be recorded as a premium paid on the acquisition of property. For EMT, **[BEGIN CUI/PRIV-HC]** [redacted] **[END CUI/PRIV-HC]** The record is devoid of any information regarding why **[BEGIN CUI/PRIV-HC]** [redacted] **[END CUI/PRIV-HC]**

As recognized by Mystic witness Heintz,[115] the Commission's policy regarding inclusion of an acquisition premium in rate base is articulated in *Seaway Crude Pipeline Co., LLC*, 154 FERC ¶ 61,070, at P 92 (2016) ("*Seaway*") (citations omitted):

> The "substantial benefits" requirement for a pipeline seeking rate-base treatment for an acquisition premium involves a two-prong test. First, the pipeline must show that the facilities will be converted from one public use to a different public use, or that the assets will be placed in FERC-jurisdictional service for the first time. Second, the pipeline must show clear and convincing evidence that its acquisition of the facilities will provide substantial, quantifiable benefits to ratepayers even if the full

[114] Exh. ENC-0083 at 2 **[BEGIN CUI/PRIV-HC]** [redacted] **[END CUI/PRIV-HC]**

[115] Exh. MYS-0037 at 14:7-21.

> purchase price, including the portion above depreciated original cost is included in rate base. The Commission also considers whether the transaction at issue is an arm's length sale between unaffiliated parties, and whether the purchase price of the asset at issue is less than the cost of constructing a comparable facility. The Commission allows an acquisition premium to be included in a pipeline's rate base when the purchase price is less than the cost of constructing comparable facilities, the facility is converted to a new use, and the transacting parties are unaffiliated.

Mr. Heintz is incorrect that ExGen's **[BEGIN CUI/PRIV-HC]** [redacted] **[END CUI/PRIV-HC]** met the Commission's two-prong "substantial benefits" test.

First, **[BEGIN CUI/PRIV-HC]** [redacted][116] **[END CUI/PRIV-HC]** EMT will continue to operate in its present use to provide LNG fuel for Mystic 8 & 9. Everett currently provides LNG service to Mystic and other customers. And Mystic confirms that it is expected to continue to provide LNG service to Mystic and others.[117] Thus, irrespective of ExGen's acquisition of EMT, EMT still will be providing the same service, *i.e.*, the same public use.

The second prong of the Commission's two-prong "substantial benefits" test requires the applicant to "show clear and convincing evidence that its acquisition of the facilities will provide substantial, quantifiable benefits to ratepayers even if the full purchase price, including the portion above depreciated original cost is included in rate base."[118] **[BEGIN CUI/PRIV-HC]**

[redacted]

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[116] *See* Exh. MYS-0020 at 12:14.

[117] Tr. 308:12-22.

[118] *Seaway* at P 92.

[redacted][119] **[END CUI/PRIV-HC]**

Seaway goes on to state that the "Commission also considers whether the transaction at issue is an arm's length sale between unaffiliated parties, and whether the purchase price of the asset at issue is less than the cost of constructing a comparable facility."[120] As Ms. Hughes testified, **[BEGIN CUI/PRIV-HC]** [redacted] **[END CUI/PRIV-HC]**[122]

Finally, Mystic has presented no evidence showing that the purchase price of the asset at issue is less than the cost of constructing a comparable facility. While counsel for Mystic cross examined Ms. Hughes on whether she knew **[BEGIN CUI/PRIV-HC]** [redacted][123] **[END CUI/PRIV-HC]** this tactic inappropriately attempts to shift the burden to NESCOE's witness to demonstrate that which Mystic failed to do so. Mystic had the opportunity to present testimony on what it

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[119] Tr. 330:2-6.

[120] *Seaway* at P 92.

[121] Exh. MYS-0054 at 45 (20-year term).

[122] Exh. NES-021 at 12:3-5.

[123] Tr. 1763:2-12.

would have cost to construct a comparable facility but did not do so.[124] The record is devoid of any such evidence.

For the reasons discussed above, Mystic has not met the criteria specified in the Commission's two-prong "substantial benefits" test to include the **[BEGIN CUI/PRIV-HC]** [redacted] **[END CUI/PRIV-HC]**[125] In addition, **[BEGIN CUI/PRIV-HC]** [redacted] **[END CUI/PRIV-HC]**

Moreover, it is questionable whether Mystic should be able to take advantage of the acquisition premium because, as Staff witness Nicholas explains, the concept of an acquisition premium is a concept applicable to rate regulated entities that follow the Commission's USoA. Mystic and Everett do not; rather, they follow GAAP.[128]

Additionally, there is record evidence that **[BEGIN CUI/PRIV-HC]** [redacted]

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[124] Tr. 1772:10-11.

[125] *Seaway* at P 92.

[126] Tr. 806:15-20; Tr. 807:3; Tr. 808:17-18.

[127] *See* Tr. 1775:1-22; Exh. NES-023 at 7-8 **[BEGIN CUI/PRIV-HC]** [redacted] **[END CUI/PRIV-HC]**.

[128] Exh. S-0025 at 17:11-16; Exh. S-0026; Exh. S-0027.

[redacted][131] **[END CUI/PRIV-HC]**

NESCOE urges the Commission to approve a rate base value for EMT equal to zero ($0). Cutting through Exelon's accounting rhetoric and contract reshuffling, at its core, Exelon is asking the Commission to approve $60 million in rate base to reflect the fair market value of an asset that will have a **[BEGIN CUI/PRIV-HC]** [redacted] **[END CUI/PRIV-HC]** The record shows that Exelon's interrelated transactions fictionalize and prop up EMT's value. Exelon viewed a continued contractual relationship with EMT as necessary to fulfill Mystic's present capacity supply obligations.[132] At the same time, a cost-of-service arrangement would relieve Exelon of the acquisition price and pass that onto consumers. Exelon structured the transaction to suit shareholder needs, not the needs of consumers, and the Commission should not allow Exelon to manufacture a rate base value of its choosing.

If, however, the Commission determines that EMT provides some benefit to ratepayers, then the rate base value should be less than the full $60 million, and should take into consideration **[BEGIN CUI/PRIV-HC]** [redacted] **[END CUI/PRIV-HC]** The testimony of Mr. Steffen may be useful in this regard.[133]

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129 *See* Exh. S-0025 at 14:17-15:12; *see also* Exh. S-0033 at 4 (NES-MYS-1-75).

130 Exh. ENC-0085 at 3-4.

131 Tr. 1774:3-6; Exh. NES-024 at 1-2.

132 *See* Transmittal Letter at 7; Exh. MYS-001 at 6:9-12; Exh. MYS-002.

133 *See* Exh. ENC-0030 at 66:3-10 ("My correction of Mr. Heintz's errors is presented in my Exhibit No. ENC-0047. My calculation, which is based on the Commission's original cost principle, is consistent with Generally Accepted Accounting Principles and with the Commission's policy that a purchaser should record acquisitions

ii. The proposed CWC for Everett is not just and reasonable and should be set to zero.

As with Mystic 8 & 9, Mystic proposed to use one-eighth of annual O&M expenses as a default value for cash working capital for EMT. For Everett, Mystic also proposed a 15-day lag in the payment for the LNG supplied to customers as a separate proposed CWC requirement.[134]

As discussed above (*see* Section I.A.1.a.iii, *supra*), Mystic has not supported its use of one-eighth of its O&M expenses as CWC in this case, and the Commission should disallow the inclusion of CWC requested from 2017 through the cost-of-service period for EMT, in addition to Mystic 8 & 9. As explained above, Mystic's proposed use of the one-eighth method does not take into account all of its costs and the revenue timing differences under the special circumstances in this case. In particular, as explained in Ms. Cannady's testimony, Mystic's request to expense all capital expenditures for EMT during the cost-of-service period greatly enhances Mystic's cash flow during this period.[135] In the absence of a reliable lead lag study that recognizes the increased cash flow from expensing all capital expenditures during the cost-of-service period, the CWC should be set at $0 from 2017 through and inclusive of the cost-of-service period and should not be a component of any true-up established in the proceeding,[136] particularly given the unprecedented level of and nature of the costs Mystic seeks to recover from consumers.

Additionally, as Ms. Cannady pointed out, there is no justification for the additional amount that Mystic originally proposed to add for "fuel lag."[137] Notably, Mystic has now

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at the lessor of depreciated original cost or the actual purchase price, demonstrates that value of net property, plant and equipment for Everett is $4,993,000, essentially equal to the value of long-term spare parts.").

[134] Exh. MYS-0006 at 12:17-19.

[135] Cannady Testimony, Exh. NES-010 at 8:7-9:12; *id.* at 9:7-9.

[136] *Id.* at 9:17-21.

[137] *Id.* at 10:1 – 12:6.

conceded to remove the fuel lag from EMT's rate base. Although no specific reason was provided, Mr. Heintz "determined that there is not a significant fuel lag with respect to the time between when Mystic burns the fuel for generation and the time it is paid for that fuel from the ISO."[138]

The impact of Mystic's use of the one-eighth method for computing CWC results in an increase in the revenue requirement during the cost-of-service period of approximately $2.3 million for EMT.[139] There would have been an additional revenue requirement of $4.0 million for the requested 15-day lag between EMT's payment for fuel and receipt of revenue associated with the fuel.[140] The Commission should direct Mystic to remove these amounts from Everett's rate base.

b. The Proposed Rate of Return On Equity for Everett Is Not Just and Reasonable.

For the reasons discussed above in Section I.A.1.b.i, the proposed rate of return on equity for Everett is not just and reasonable.

2. The Proposal to Allocate All of Everett's Fixed Costs to Mystic With a 50% Credit for Third Party Sales of LNG Is Unjust and Unreasonable.

Mystic seeks guaranteed, full cost recovery for the fixed costs of the Everett facility it recently acquired to satisfy existing performance obligations. It proposes to recover those costs from New England electricity customers through the Monthly Fuel Supply Cost. The Monthly Fuel Supply Cost is a component of the Maximum Monthly Fixed Cost Payment formula set forth in Schedule 3 to the Agreement. Mystic's proposal for full cost-of-service recovery of the assets of an affiliated company—which will serve customers other than Mystic 8 & 9—and for

138 Heintz Rebuttal Testimony, Exh. MYS-0037 at 19:1-4.

139 Cannady Testimony, Exh. NES-010 at 6:3.

140 *Id*. at 6:3-5; *see also* Exh. NES-013 at 1 (Schedule CTC-1).

the recovery of costs incurred under what would otherwise be a non-jurisdictional agreement is unprecedented. The Commission found that "for purposes of this proceeding," the Mystic-Everett relationship puts the costs related to the operation of Everett squarely within "the Commission's general practice regarding cost-of-service rates[.]"[141] Mystic has not shown that its proposal assuring full cost recovery of Everett's fixed costs is just and reasonable, and a number of its proposed changes altering the *pro forma* on file with the Commission are unjust and unreasonable. The Commission should reject these aspects of the Mystic proposal. NESCOE urges the Commission to modify the proposed Agreement in ways discussed below to align with the Agreement's fuel security objectives[142] and to promote consumer interests.

As set forth in Schedule 3, Mystic proposes a new Monthly Fuel Supply Cost that would be set equal to the Fuel Supply Cost that is defined in the FSA and invoiced to Mystic on a monthly basis.[143] The Fuel Supply Cost comprises everything but the separately defined commodity cost—*i.e.*, it includes Everett's fixed and variable operations and maintenance costs, allowed return on shareholder equity, regulatory costs, administrative services fees, credit and collateral costs, pipeline transportation agreement costs, potential cargo diversion costs, gains or losses from gas sales to third-party customers, and an actual fuel cost adjustment.[144] The structure of the agreement under which all costs, including gains/losses from sales to other customers, will be recovered is very unusual and leans on an incentive structure—that did not have the benefit of ISO-NE analysis[145]—to operate efficiently. The incentive structure was

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[141] Hearing Order at P 36.

[142] *See, e.g.*, Exh. NES-003 at 2 (ISO-NE explanation that its "objectives for the agreement were to ensure that the Mystic units would have the incentive to maintain sufficient fuel on site to be available during times of critical need in the winter months.")

[143] Exh. MYS-0016 at 5; Hearing Order at P 16, n.22.

[144] Exh. MYS-0016 at 5.

[145] Exh. NES-038 at 1; Ethier Answering Testimony, Exh. ISO-001 at 32:4-5.

instead an untested, unanalyzed idea that came with unknown consumer cost implications.[146] NESCOE and others[147] pointed out serious concerns with this arrangement. The Hearing Order found that Mystic had not provided information sufficient for the Commission to determine the justness and reasonableness of the Monthly Fuel Supply Cost, and it directed participants to address at hearing the justness and reasonableness of Mystic's proposal.[148] In finding jurisdiction over the Fuel Supply Charge as a component of the cost-of-service rate, the Commission stated that such a finding "does not mean that Mystic is entitled to recover all costs that it claims in connection with the Distrigas Facility."[149]

a. Mystic's Approach Would Pass Excessive Costs Onto Consumers and Should Not Be Adopted Without Material Modifications.

Based on the evidentiary record developed in this case, the Commission should find that (i) the FSA price terms as proposed to be passed through Schedule 3's Monthly Fuel Supply Cost are not just and reasonable, (ii) the outermost bound for which Mystic is entitled to recover for its Everett affiliate is 39% of that facility's fixed costs, and (iii) Mystic should employ a more simple, straightforward, and standard approach to the fuel supply relationship to enhance Everett's efficiency and reduce the risks and costs to consumers. Under the FSA as proposed, Mystic's affiliate would have no incentive to manage Everett effectively, resulting in excessive cost passed through to customers and harm to regional gas and electric markets.

NESCOE sponsored expert witness and economist James F. Wilson, who has thirty-five years of consulting experience to the electric power and natural gas industries in the U.S. and

[146] Exh. NES-038 at 1; Ethier Answering Testimony, Exh. ISO-001 at 32:4-5.

[147] *See, e.g.*, Exh. NEE-001 at 2-3, Exh. REP-001 at 4:17-19.

[148] Hearing Order at PP 34, 37.

[149] *Id*. at P 37.

abroad.[150] Mr. Wilson performed an extensive analysis of the Agreement, the FSA and documents and responses of Mystic and ISO-NE in the discovery phase of this proceeding.[151] Based on that analysis, Mr. Wilson concluded that the arrangement does not provide sufficient incentive to operate the facility efficiently and results in excessive charges to consumers. Accordingly, Mr. Wilson recommended modifications to the FSA that align the affiliated Exelon companies' performance with the fuel security needs of the New England system and the interests of consumers bearing the costs under the Agreement.

These modifications are reflected in Attachment B hereto, a redlined copy of the FSA illustrating the changes required to implement Mr. Wilson's recommendations. Similarly, Attachment A hereto is a redlined copy of the Agreement reflecting conforming changes to the implement these recommendations.[152] Attachment A also includes changes to reflect Mr. Bentz's recommendations, discussed *infra* at Sections I.D, III. These mark-ups are intended to serve as a model for how the Agreement (and its related components) could be revised to effectuate the structure that Mr. Wilson recommends.[153]

Mr. Wilson explains that his recommended changes to the FSA would provide a "more straightforward, efficient and understandable contractual relationship" between Constellation LNG (the seller) and Mystic (the buyer).[154] It would also "lead to more efficient operation of EMT and lower cost passed through to consumers" compared with the FSA that Mystic has filed

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[150] Wilson Testimony, Exh. NES-028 at 2:6-3:2; Exh. NES-029.

[151] Wilson Testimony, Exh. NES-028.

[152] Attachment A is NESCOE's mark up of the Agreement (omitting privileged Schedules 1 and 2).

[153] These mark-ups in Attachments A and B represent NESCOE's best efforts given the time constraints, and may not capture every modification needed to make the agreements just and reasonable. NESCOE has put in placeholders for the rates to be collected because the rates as proposed require a number of modifications to ensure they are just and reasonable.

[154] Wilson Testimony, Exh. NES-028 at 26:18.

with the Commission.[155] To this end, Mr. Wilson proposes that the catch-all Fuel Supply Charge be modified so that the FSA contains three categories of charges that pass through in the Monthly Fuel Supply Cost in Schedule 3 of the Agreement: a Demand Charge, a Commodity Charge, and a Reliability Charge.[156] As Mr. Wilson explains, this approach would reflect commercial practices common to the industry and would provide Constellation LNG with an opportunity to recover Everett's costs "from *all* of its various customers, rather than shifting all of these costs to Mystic (and, through the [Agreement], to electricity consumers)."[157]

The proposed allocation of 39.16% of fixed cost to Mystic would afford Constellation LNG full flexibility to serve other customers, and keep all margins, providing a reasonable opportunity to recover the other 60% of costs. This approach, together with the implementation of the Reliability Charge, appropriately places Constellation LNG in the position of managing the EMT for its benefit and limits EMT operational risks being passed onto consumers.

Demand Charge. The Demand Charge generally reflects Everett's fixed costs, and includes several but not all components of the FSA's Fuel Supply Charge—*e.g.*, Fixed O&M/Return on Investment Costs, New Regulatory Costs, and Administrative Services Fee.[158] Mystic's proposal that seeks full recovery of every component cost listed in the Fuel Supply Cost is not a just and reasonable one. By contrast, Mr. Wilson recommends that the Commission allow for a share of cost recovery that is equal to the maximum capacity that Mystic can receive from Everett on a daily basis, as a fraction of its certificated capacity.[159] The Demand Charge would permit cost recovery for Everett through the Agreement based on the appropriate portion

155 *Id*. at 8:16-17.

156 *Id*. at 26:19-27:21.

157 *Id*. at 26:6-18 (emphasis supplied).

158 *Id*. at 26:21-27:7.

159 The Demand Charge is described in Attachment B at 2-4.

of Everett's fixed costs informed by the upper limit of Mystic's fuel take. This share of authorized cost recovery would be not more than 39.16%[160] and is equivalent to the ratio of Everett's maximum daily send out to Mystic of 280,000 MMBtu/day to its FERC-certificated capacity of 715,000 MMBtu/day.[161] If Mr. Wilson's calculation were based on historical sendout to Mystic, the allowed percentage would be even lower.[162] NESCOE notes that Staff's recommended 91% allocation[163] is too high. Staff only removes the trucking piece and all other sales to the pipeline are left in the percentage. In other words, Staff only subtracts *one* source of merchant revenue stream, not *all* sources.

Mystic's preference for full fixed cost recovery of Everett has not been shown to be just and reasonable. Mystic's witness Michael M. Schnitzer contends that the full costs of Everett should be allocated to Mystic because Everett is the sole source of fuel for Mystic.[164] As a threshold matter, based on ExGen's recent acquisition of EMT, the Commission must reject Constellation LNG's assignment of full costs and risks to Mystic and thus consumers. As of October 1, 2018,[165] the monopoly supplier with exclusive control over the essential fuel input into production is now Mystic's affiliate (Constellation LNG), and it is not, therefore, just and reasonable for the Commission to simply assign the full fixed cost of that affiliate monopoly supplier to Mystic. Such an arrangement is anticompetitive, unjust and unreasonable.[166] In this

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[160] Attachment B at 2.

[161] At the hearing, ISO-NE witness Levitan confirmed this vaporization send-out from EMT to Mystic and other facilities. Tr. 1177:1-14. Wilson Testimony, Exh. NES-028 at 26:21-27:7; *see id*. at 36:1-2; CT-064 (FERC-certificated capacity of EMT is 715,000 MMBTU/day).

[162] Tr. 856:15-17.

[163] Exh. S-0001 at 21:2-9.

[164] Tr: 757:14-19 ("I think that Everett is needed for Mystic 8 and 9 to have gas under all circumstances").

[165] Exelon's purchase of Everett closed on October 1, 2018. Tr. 741:6-10.

case, under Mystic's proposal, the adverse consequences of the anticompetitive monopolistic framework fall on consumers.

Mystic has also not shown that its proposal to recover the full fixed costs for Everett is just and reasonable because Constellation LNG has ample opportunity to recover, and should be recovering, some of Everett's costs on competitive, commercial terms from sales to customers other than Mystic. This is the same way that the facility's owners have earned revenue throughout its history. It is undisputed that Everett has for many years served many other customers,[167] and Constellation LNG could make sales to other parties, even during the winter months. [168] There is also no dispute that Everett is a pivotal supplier of natural gas when New England needs it most.[169] Mr. Wilson's recommendation to restructure the FSA and allocate a proportionate share of Everett's fixed costs to Mystic is eminently reasonable because it would ensure that Constellation LNG is incentivized to market Everett's services to other customers consistent with prior facility practice. This would provide reliability to the New England electric system while ensuring that Mystic's customers are not paying excessive rates.

A world in which Everett's operator has little or no interest in making third-party sales—the consequence of allocating all costs to Mystic—is of paramount concern to ISO-NE. Exh. NEE-050 at 2 ("Given that the Distrigas facility is capable of injecting as much as 435 mcf into the gas pipeline system, the ISO wanted to establish a structure that provides Exelon with incentives to pursue third-party sales. Absent such incentives, the ISO is concerned that Exelon

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166 *Gulf States Utils. Co. v. FPC*, 411 U.S. 747, 760 (1973) ("Consideration of antitrust and anticompetitive issues by the Commission . . . serves the important function of establishing a first line of defense against those competitive practices that might later be the subject of antitrust proceedings").

167 Exh. ISO-002 at 5:18-21.

168 Schnitzer Supplemental Testimony, Exh. MYS-014 at 23:12-14; 25:18-19.

169 Tr. 762:14-17 (Schnitzer) (agreeing that Everett can be a pivotal supplier of natural gas in New England during peak demand periods); Tr. 760:3-14 (discussing Exh. ENC-125); Exh. EDF-008 (EMT is "critical to addressing the ISO-NE region's fuel security and reliability issues").

might seek to use Distrigas solely for the purpose of providing fuel to Mystic 8 and 9, thereby depriving the region of the significant additional benefits"). Mystic can, as a practical matter, receive no more than about 40% of Everett's sustainable, certificated capacity.[170] The remaining capacity of Everett—which is at least 60% and usually more—is available to other customers, including gas distribution companies and other wholesale electric generators.[171] The allocation of a portion of the fixed costs to Mystic is appropriate and, unlike full fixed cost recovery would not "undermine the behavioral incentives" that ISO-NE is concerned may occur under the cost-of-service compensation.[172]

The Commission should also reject other reasons that Mystic proffers to justify full cost recovery of Everett. Mr. Schnitzer contends that the operations of the Mystic Units and Everett are integrated,[173] but such a rationale would be a slender reed on which to find justification for his cost allocation proposal. The Commission routinely allocates the costs of integrated and interdependent systems. In fact, Mr. Schnitzer is unaware of any situation involving a FERC-regulated natural gas facility where a customer that is using less than 100% of that facility's service would pay for the full 100% of that service.[174] Even if the Commission agreed with Mr. Schnitzer's view that these formerly unaffiliated companies had a high degree of physical integration, Mr. Wilson's approach provides for a fair allocation of costs using the capacity of Everett to serve Mystic and would not require the intensive cost-causation determinations Mr. Schnitzer believes to be so difficult.

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[170] Exh. ISO-002 at 9:15.

[171] Wilson Testimony, Exh. NES-028 at 36:1-5; Levitan Answering Testimony, Exh. ISO-002, at 7-8; Tr. 1177:1-14.

[172] Exh. NEE-050 at 9 ("This COS treatment can have the effect of undermining the behavioral incentives associated with market constructs relative to those faced by for-profit entities.").

[173] Schnitzer Supplemental Testimony, Exh. MYS-014 at 21:4-23; 24:13-21.

[174] Tr. 872:20-873:7 (Schnitzer).

In short, Mystic has not demonstrated that the full allocation of EMT costs to Mystic 8 & 9 is just and reasonable. In contrast, the proposal put forth by Mr. Wilson is a just and reasonable approach. It uses the maximum capability of Everett to serve Mystic to determine the maximum share of fixed costs provided by Mystic to Everett as compensation for fuel supply, promoting a more efficient operation of EMT and safeguarding against excessive costs passed to consumers through the Agreement.

Commodity Charge. The second charge that Mr. Wilson recommends is the Commodity Charge for actual volumes taken.[175] NESCOE's recommended approach to the Commodity Charge[176] is based on Mr. Wilson's conceptual approach. Without varying materially from Mr. Wilson's recommendation, NESCOE's proposed definition reflects an even simpler approach appropriate for the limited two-year agreement at issue.

Reliability Charge. The third charge recommended by Mr. Wilson is an Annual Reliability Charge to compensate Constellation LNG for additional costs and risks associated with providing firm and flexible service to Mystic.[177] This is an important change to protect consumers from unwarranted risks. Mr. Wilson explains that "[w]hile the usual practice in such an agreement might be to reflect such costs and risks through a higher Demand Charge, it will be clearer to separate out the fixed cost recovery from the costs related to reliable service."[178] Such transparency is important where, as here, the purpose of the Agreement is to provide fuel security that ISO-NE has determined is necessary for reliability, and the cost components are the subject of this regulatory proceeding, rather than elements of a bilateral commercial transaction.

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[175] Exh. NES-028 at 27:8-14.

[176] Attachment B at 4.

[177] Attachment B at 4-6.

[178] Wilson Testimony, Exh. NES-028 at 28:18-21.

The Annual Reliability Charge would be fixed in advance of each winter period and cover (in expectation) additional costs and risks related to providing firm, reliable and flexible fuel supply that is required from Mystic (and by extension Everett) throughout the winter season.[179] Accordingly, the Annual Reliability Charge would not compensate for *actual* costs, but would instead provide a payment based on an *ex ante* estimate of costs. This will afford Constellation LNG the incentives to *minimize actual* costs and relieve consumers of exposure to unknown tank management costs over which they have no control. Effectively, this feature of Mr. Wilson's recommended approach places the risk of managing fuel on the party that has the best ability of controlling and managing that risk, Constellation LNG. Exelon has acknowledged that the Reliability Charge concept does not generally present an unacceptable business risk, subject to its "overall cost recovery and structure."[180] This approach is also most consistent with the risk-shifting objective of restructuring and associated divestiture.[181]

For instance, the Annual Reliability Charge would cover Constellation LNG's expected costs for tank management and the risk of exposure to penalties if the tank management is unsuccessful and results in a fuel outage. Tank management costs would include the potential credits to Mystic when Constellation LNG requests that the Mystic Units be self-scheduled for tank management purposes. It could also include the loss of energy market revenues when an "opportunity cost" is added to Mystic's Stipulated Variable Cost ("SVC") at Everett's request and as ISO-NE allows, in order to avoid dispatch and conserve fuel supply. Tank management costs may also include costs resulting from Constellation LNG's choices to sell excess gas at a loss to make room in the tank for an incoming cargo, costs to delay, downsize, cancel, or divert a

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[179] *Id*. at 27:15-17.

[180] Exh. NES-042 at 1.

[181] *See Electric Restructuring*, *supra* note 20.

scheduled cargo. The Reliability Charge should also cover penalties in the Agreement that Mystic could incur (and charge back to Everett through the FSA) as a result of a fuel shortage or fuel outage resulting from, for example, Everett's mismanagement of fuel supplies. These costs are not compensated as incurred, but the possibility that such costs may be incurred is anticipated in the Reliability Charge.

Before the winter season begins, the Annual Reliability Charge would be set and therefore known to Mystic and Everett. The Annual Reliability Charge would be set using a probabilistic simulation to model Everett's operations to provide service to Mystic. As Mr. Wilson explains, the simulation model would be similar to the tank congestion charge model that Mystic proposes for use in the FSA; however, that model would be modified.[182] This concept is laid out in more detail in Schedule A of Attachment B.[183] Mr. Wilson built the Reliability Charge model based on the Tank Congestion model and reflected these elements of the Annual Reliability Charge. (This model was shared with the parties in the discovery process as part of Mr. Wilson's workpapers.)

3. Certain Remaining Components of the Monthly Fuel Supply Cost Are Not Just and Reasonable, and Certain Terms and Conditions of the FSA Result In Rates Under the Mystic Agreement That Are Unjust and Unreasonable.

a. The FSA Does Not Result In Just and Reasonable Fuel Charges for Mystic 8 & 9.

i. The Commission should reject Mystic's proposed credit for third-party sales.

For the reasons described in Section I.B.1, the Commission should find that Mystic has not carried its burden to show that full cost-of-service recovery for the Everett facility through

[182] Wilson Testimony, Exh. NES-028 at 32:13-14; *see also* Exh. NES-034.

[183] Attachment B at 15-16.

the FSA's proposed Fuel Supply Charge and the Actual Fuel Cost Adjustment in Schedule 3 of the Agreement is just and reasonable. The evidentiary record shows, to the contrary, that the Mystic proposal (i) falls short of providing the appropriate incentives for Constellation LNG to deploy its newly acquired Everett assets to provide services to third parties, (ii) potentially deprives other customers, including gas distribution companies and wholesale electric generators other than the Mystic Units, of needed fuel supply, (iii) disincentivizes a more efficient operation of EMT, and (iv) exposes consumers to excessive costs by relieving shareholders of the risk of management's business decisions. The Commission should reject the Mystic proposal and instead issue an order that adopts the three-part pricing approach that Mr. Wilson developed. At a minimum, the Commission's order should require that Everett receive not more than the 39.16% share of its fixed costs from Mystic, as is proportionate to the facility's actual capability to serve Mystic.

If the Commission declines to adopt these approaches, and instead decides that Mystic may pass through to a single customer the full fixed cost of service for Everett, it should make a change to the FSA's provision specifying "Third-Party Sales Credit for Demand Charges."[184] This provision as proposed provides for an "incentive retained by Constellation LNG" for forward sales to buyers other than Mystic that are executed three or more months in advance.[185] Constellation LNG would retain one-half of the as-defined margin on those transactions. The Commission should reject this approach.

The margin is not the actual profit realized on the transaction; it is specified instead as the contract revenue less the sum of (i) Constellation LNG's "total variable costs" that it expects to

[184] Exh. MYS-0016 at 3-5.

[185] Schnitzer Supplemental Testimony, Exh. MYS-0014 at 4:11; Exh. MYS-0016 at 4; Wilson Testimony, Exh. NES-028 at 40:19-41:7.

incur with that transaction and (ii) a tank congestion charge produced by a to-be-developed and ISO-approved methodology. On shorter-term sales made less than three months' forward, Constellation LNG would receive no share of the as-defined margin.

Mystic's proposal to give Constellation LNG one-half of the as-defined margin is not just and reasonable, and the Commission should reject it. Exelon does not need a margin on these transactions to recover the costs of the Everett facilities, and in fact the proposal to retain a share of the margin would result in charges through the Agreement that exceed Everett's cost of service. Constellation LNG's proposed margin share is therefore too high when paired with a Commission decision to allow Mystic to charge for the full fixed cost recovery of Everett.

Any margin-sharing would be a windfall to Constellation LNG that results in dividends accruing to Exelon. Mystic's witness, Mr. Schnitzer, represented that during contract negotiations, Exelon was willing to flow through all third-party sales margins as a credit in the Agreement,[186] but that it was ISO-NE that wanted the provision in order to "provid[e] an incentive for Exelon to make third-party sales from Everett to further contribute to regional fuel supply."[187] Further, according to Mr. Schnitzer, **[BEGIN CUI/PRIV-HC]** [redacted][188] **[END CUI/PRIV-HC]**

Mystic, however, opportunistically shifts its prior position and seemingly opposes any change to the FSA that would reduce Constellation LNG's share of the as-defined margin, contending that the incentive is now necessary to reward Constellation LNG and its traders for entering into this type of forward third-party sale.[189] During cross-examination, Mr. Schnitzer

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[186] Schnitzer Supplemental Testimony, Exh. MYS-0014 at 25:1-3

[187] *Id*. at 25:3-4.

[188] Schnitzer Rebuttal Testimony, Exh. MYS-0054 at 5:11-13; *see also* Tr. 841:1-842:5.

[189] Schnitzer Supplemental Testimony, Exh. MYS-0014 at 24:22-25:16.

conceded that **[BEGIN CUI/PRIV-HC]** [redacted][191] **[END CUI/PRIV-HC]** is hardly reasoned analyses in support of such a proposal and should not be accorded any weight.[192]

Likewise, there is nothing in the record that suggests that ISO-NE's proposal for a margin-sharing arrangement providing Constellation LNG with one-half of the as-defined margin was ever viewed by ISO-NE management as necessary for reliability. "The ISO did not perform a formal analysis to establish the proposed 50% margin-sharing for third-party LNG sales."[193] Instead, the margin-sharing arrangement proposed in the FSA was crafted as a starting point for negotiation. As Robert G. Ethier, ISO-NE's Vice President of Market Operations stated, "the ISO agreed to those percentages largely as a placeholder, with the understanding that the division of margin would be reviewed by the Commission and, perhaps, negotiated by all parties . . .".[194] Dr. Ethier's views as to what percentage of margin-sharing "may not be sufficient" in his opinion[195] are based on conjecture.

Mystic's proposed margin-sharing arrangement is overly generous to Constellation LNG. It would also allow Constellation LNG to earn margins even when the transaction is not profitable, *i.e.*, the actual margin turns out to be less than Constellation LNG's *ex ante* take or

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190 Tr. 846:2-20 (Schnitzer) ("There was no analysis").

191 *See* Tr. 849:3-13 (Schnitzer) .

192 *See* Exh. NES-046 at 6 (providing example) and at 7 (discussing credit and payment risk).

193 Exh. NES-038 at 1; Ethier Answering Testimony, Exh. ISO-001 at 31:18-20.

194 Ethier Answering Testimony, Exh. ISO-001 at 32:3-5.

195 Ethier Cross-Answering Testimony, Exh. ISO-015 at 14:2-3.

even less.[196] ("There shall be no subsequent adjustment to such Seller's Incentive calculation based on actual deliveries of Gas or LNG thereunder."). While the FSA seems to address this issue by prohibiting Constellation LNG from entering into forward transactions with prices "less than Seller's cost of LNG supply… at the time of execution…,"[197] this prohibition would not protect customers in any transactions that lose money at the end of the day. All actual losses incurred by Constellation LNG will be passed through to Mystic by way of the Monthly Fuel Supply Cost that is a component of the Maximum Monthly Fixed Cost Payment formula in Schedule 3 to the Agreement—even though Constellation LNG will have collected its share of expected margin upfront on the transaction.[198] Mystic witness Mr. Schnitzer [**BEGIN CUI/PRIV-HC]** [redacted][201] **[END CUI/PRIV-HC]**

No evidentiary basis exists for the Commission to find that the proposed margin-sharing arrangement—about which the Commission has already expressed concerns[202]—is just and reasonable. As Mr. Wilson explains, under the proposed FSA, Constellation LNG as the seller in

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[196] Exh. MYS-0016 at 5.

[197] *Id*. (section (vii)).

[198] Wilson Testimony, Exh. NES-028 at 41:8-19; *see also* Exh. NES-031 at 12 (response to NEER-MYS-2-9) (noting conflict of interest and commodity risk issues).

[199] Tr. 838:15-839:2.

[200] Tr. 839:16-840:1.

[201] *Id.* at 845:4-20.

[202] Hearing Order at P 38 ("allowing Mystic to keep 50 percent of the margin on third-party sale appears to be excessive.")(footnote omitted).

third-party transactions does not bear any risk of these transactions. If the sale turns out to be a loss, then 100% of the loss is passed through to customers through the Agreement's Schedule 3 Monthly Fuel Supply Cost. Because Constellation bears no risk of actual loss (and in fact has already collected its margin), it has no incentive to manage these transactions in a way to avoid actual loss. These considerations ultimately lead to the conclusion that the proposed as-defined margin sharing mechanism is too favorable to Constellation LNG.

NESCOE urges the Commission to adopt Mr. Wilson's recommendation to reduce the share of as-defined margin that would go to Constellation LNG from 50% to 25%, if the proposal to adopt NESCOE's entirely different approach to the FSA is rejected.[203] This approach balances the competing interests that Mr. Wilson discusses and the risk to consumers. As Mr. Wilson notes, if "Constellation LNG is highly risk averse and disinclined to engage in third party transactions,"[204] the absence of a margin-sharing mechanism could would eliminate the potential for third-party profits to offset the costs of the Everett facility, causing consumers to bear 100% of the costs.

ii. If the Commission does not adopt Mr. Wilson's proposed approach including the reliability charge, the Commission must direct further changes to components of the monthly fuel supply charge.

Mr. Wilson testifies about the fuel opportunity costs component of the SVC in Section 3.4 of the Agreement. The SVC is the formula that determines the Mystic Units' offer price into the New England energy markets. The SVC formula is a critical element of the Agreement

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203 Mr. Wilson also recommends increasing Constellation LNG's share of the as-defined margin on spot sales from zero percent, with a ten percent incentive warranting consideration. Exh. NES-028 at 40:12. While NESCOE appreciates Mr. Wilson recommendation on spot sales, NESCOE understands that implementation of the recommended spot sale incentive may raise other concerns and is therefore not recommending that the Commission adopt any change to spot sale margins.

204 Exh. NES-028 at 43:10-11.

because it determines the economic dispatch of the facilities. One of the inputs in the SVC formula is the "fuel opportunity cost." The fuel opportunity cost is (i) the amount, if any by which the AGT (citygate) fuel index price exceeds a defined Fuel Index Price,[205] and/or (ii) the opportunity cost associated with a limited supply of fuel, as approved by ISO and ISO Market Monitoring.[206]

Mr. Wilson agrees with the general view that using an opportunity cost adder in the SVC helps to ensure that the fuel supply for Mystic 8&9 is used optimally, particularly in two scenarios. The first scenario would be where regional natural gas prices (as represented by a proxy AGT price) are high. In this case, natural gas from Everett may be more valuable delivered to the pipelines than to the Mystic Units.[207] At times, some of Everett's supply that could be delivered to the Mystic Units could instead be delivered to the New England natural gas markets through Everett's pipeline interconnections. In this circumstance, regional natural gas prices serve as an "opportunity cost" for the use of fuel by the Mystic Units. However, it is often the case that not all of the conserved fuel can be sold. For instance, Everett's pipeline capacity may already be committed to sales to other customers, or there may be insufficient capacity, pressure, or demand downstream to accept the supplies.

Mr. Wilson proposes that to better represent the opportunity cost of the Mystic Units' energy under this first scenario, the Agreement should provide that this energy should at times be offered in two blocks, with two SVCs and resulting offer prices: one block would correspond to the natural gas volumes that could otherwise go to the pipelines, and for which the offer price

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205 The Fuel Index Price, defined in section 3.4.1.3, is the current daily price determined using a world LNG index, or alternatively, and subject to approval by ISO Market Monitoring, the weighted average cost of gas in the storage tank adjacent to the LNG Terminal. Agreement, § 3.4.1.3.

206 Agreement, § 3.4.1.4.

207 Wilson Testimony, Exh. NES-028 at 37:12-14.

would reflect the AGT opportunity cost; and another block for natural gas volumes that could not go to the pipelines, and for which the AGT price is not an opportunity cost. Of course, this approach that Mr. Wilson recommends would only work if Constellation LNG would actually offer Everett's gas supplies into the markets at those times.

The second circumstance is when the supply of fuel is limited. Mr. Wilson explains that under these circumstances, the fuel should be valued at a price higher than its replacement cost.[208] As Mr. Wilson points out, ISO-NE is continuing to refine its rules regarding opportunity costs to reflect limited fuel-supply.[209] Mr. Schnitzer agreed with Mr. Wilson's concerns:

> I agree with Mr. Wilson's observation that the opportunity cost adder should be conditioned on Everett's physical capability to make the third-party sale. Likewise, I agree with his observation that the opportunity cost adder based on an expectation of future prices must be carefully constructed to avoid an opportunity cost adder that is either too low or too high.[[210]]

The Commission should require that the Agreement is modified consistent with Mr. Wilson's recommendations regarding the opportunity cost adder.

Finally, Section 4.4.3 of the Agreement is intended to provide that when Mystic offers and is dispatched based on an opportunity cost adder, the calculation of the energy margin to be flowed back to customers captures the full margin benefit from any Mystic 8&9 dispatch (including the margin from an opportunity cost-based energy offer). Mr. Schnitzer testifies that the section failed to accomplish that intent.[211] NESCOE understands that Exelon and ISO-NE agree that a revision to correct the error is necessary, and to this end Mr. Schnitzer proposed

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[208] *Id.* at 37:14-15.

[209] *Id*. at 38:17-18 (citing Memo from Jon Lowell to NEPOOL Markets Committee, Opportunity Costs for Resources with Inter-temporal Production Limitations, July 27, 2018, available at https://www.iso-ne.com/staticassets/documents/2018/07/a3_iso_memo_re_opportunity_costs.pdf.).

[210] Schnitzer Rebuttal Testimony, Exh. MYS-0053 at 42:1-5.

[211] Schnitzer Supplemental Testimony, Exh. MYS-014 at 12:11-13:31.

language to address this error.[212] Section 4.4.3 of the Agreement must be modified to account for the opportunity cost adder; otherwise Mystic would receive a windfall each time the adder is deployed. Accordingly, the Commission's Order should further direct ISO-NE and Mystic to modify the Agreement consistent with this recommendation.

C. The Proposed Schedule 3A Is Not Just and Reasonable.

1. Mystic's Proposed Schedule 3A Would Hardwire a Transparency Lag Into the Information Exchange Process, Fails to Include Reasonable Limitations on Certain Costs, and Unfairly Tilts the Proposed True-Up Process and Challenge Protocols in Mystic's Favor.

The Commission should reject Mystic's proposed true-up and challenge process as unjust and unreasonable. It should direct Mystic to revise its proposed Schedule 3A to ensure that: (i) consumers have timely information about expenses for which Mystic is seeking recovery under the Agreement, (ii) a fair and equitable process is in place so that consumers can understand and, as necessary, challenge these expenses, and (iii) certain categories of costs are limited and not subject to true-up. NESCOE includes as Attachment C its recommended changes to proposed Schedule 3A to rebalance the true-up and challenge process ("NESCOE Revisions").[213]

In the Hearing Order, the Commission found that "Mystic should be allowed to collect actual prudently incurred costs, on a formulary basis subject to true-up, with the prudence of such costs to be reviewed in a future Commission proceeding when the costs are actually known."[214] The Commission further found that "given the inherent difficulty in projecting costs

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[212] *Id*. at 13:2-3. *See also* Tr. 788:6-790:20 **[BEGIN CUI/PRIV-HC]** [redacted] **[END CUI/PRIV-HC]**

[213] In the interest of efficiency, Attachment C does not include the true-up methodology template; however, the template will need to be updated to reflect any changes to Schedule 3A. The NESCOE Revisions in Attachment C are the same, or are consistent with, the recommendations of NESCOE witness Cannady that are reflected in Exh. NES-020.

[214] Hearing Order at P 20.

in advance of the Agreement's effective date, and the concerns raised as to whether certain expenditures will be necessary to keep the Mystic Units operational during the proposed service period, a true-up mechanism is necessary to ensure that the rates established reflect actual costs incurred."[215] The Commission directed participants to "present evidence regarding the appropriate design of the true-up mechanism in the Agreement."[216]

Mystic has proposed Schedule 3A in response to the Commission's directives. Mystic revised its initial proposal (Exhibit MYS-022) in connection with its rebuttal testimony in this proceeding, proposing a new Schedule 3A as Exhibits MYS-0051 and MYS-0052 (the redline and clean versions, respectively).

While Mystic included in its revised version some of the changes that NESCOE's expert witness, Ms. Cannady, had proposed in her answering testimony, Mystic disregarded or rejected key protections for consumers. First, its proposal denies consumers timely information regarding capital expenditures made prior to the cost-of-service period—what effectively results in a transparency lag. Second, Mystic's proposal fails to provide limitations on the true-up adjustment for costs that should be disallowed or capped, specifically CWC, overtime and incentive pay, and total O&M costs. Third, Mystic unnecessarily restricts the inputs subject to the true-up filings based on a misreading of the Hearing Order. Finally, Mystic includes arbitrary limitations in the information exchange process and challenge procedures. These limit the ability of interested parties to receive information about the costs Mystic seeks to recover and they erect barriers to challenging costs. For the reasons discussed below, the Commission should direct Mystic to adopt the further changes reflected in the NESCOE Revisions.

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[215] *Id.*

[216] *Id.*

a. Mystic Should Provide Timely Information Regarding Costs Incurred Prior to the Term.

In her answering testimony, Ms. Cannady recommended that, prior to the cost-of-service period, Mystic be required to make informational filings with the Commission detailing the capital expenditures made for the Mystic Units and EMT over the preceding calendar year.[217] These informational filings would give interested parties a timely "opportunity to review and begin to assess the prudency of capital" for which Mystic will seek recovery from consumers.[218] To facilitate the review of these expenditures, Ms. Cannady proposed a limited opportunity for parties to ask Mystic questions, restricting each party to twenty questions per year and only allowing questions related to the capital additions.[219] These administrative filings would not initiate the challenge process, but the information and data gathered in the reasonable and limited process could be used as part of the later information exchange and challenge procedures.[220]

Mystic shrugged off this recommended change with little discussion. Mr. Heintz dismissed it as "an additional administrative burden and expense that I view as unnecessary."[221] He stated that "intervenors will be given the opportunity to review all capital expenditures incurred between 2018 and the beginning of the term, ask discovery, and have all of the protections of the protocols at the appropriate time."[222]

Setting aside other serious issues with the proposed challenge protocols, which are discussed below, Mr. Heintz glossed over the four-year lag between a cost incurred in 2018 and

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[217] Cannady Testimony, Exh. NES-010 at 27:6-8.

[218] *Id*. at 27:9-10.

[219] *Id*. at 27:16-18.

[220] *See* NESCOE Revisions, Attachment C at 3, Section I.C ("In connection with the Filings, Interested Parties may use information and data provided in an Administrative Filing and responses to interrogatory requests as part of the Information Exchange and Challenge Procedures detailed in Section II").

[221] Heintz Rebuttal Testimony, Exh. MYS-0037 at 32:20.

[222] *Id*. at 20:21-22 - 33:1-2.

the review of that cost as part of Mystic's proposed 2022 filing.[223] This consideration of and response to core consumer interests is endemic of Mystic's filing as a whole. As discussed in the Statement of the Case, *supra* at pp. 7-8, there is, and has been, an information disparity in this proceeding, compounded by the extreme time compression, which favors Mystic as the party with the cost information. Going forward, consumer-interested parties' ability to obtain timely, complete, and accurate information about Mystic's costs is critical to closing this information gap and properly protecting consumers' economic interests.

The Commission should direct Mystic to incorporate into Schedule 3A the "Administrative Filings" reflected in the NESCOE Revisions.[224] Any efforts Mystic may expend to explain consumer-funded capital expenditures closer to their incurrence—what Mystic calls a "burden"—is outweighed by the consumer interests involved. Timely notification of the capital expenditures incurred before cost-of-service period provides consumer-interested parties and others with the ability to monitor and observe changes in rate base as they occur, rather than potentially years later as Mystic has proposed.

In addition, the Commission should require that Schedule 3A be explicit that capital expenditures incurred prior to the cost-of-service period will be subject to the Information Exchange and Challenge Procedures. Mr. Heintz explained at the hearing that this was the intent.[225] However, to prevent any misunderstanding, Schedule 3A should be clarified as set forth in the NESCOE Revisions.[226]

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[223] *See* Schedule 3A, Exh. MYS-0051 at 4 ("At this time, net plant will be updated to include actual capital expenditures and depreciation incurred between January 1, 2018 and December 31, 2021.").

[224] *See* NESCOE Revisions, Attachment C at 2-3, Section I.B.

[225] *See generally* Tr. 313 – 320.

[226] NESCOE Revisions, Attachment C at 3, Section I.C: ("Each of the [Filings] . . . are subject to and will be made in accordance with the Information Exchange and Challenge Procedures detailed in Section II**, including any capital expenditures incurred prior to the Term (i.e., between January 1, 2018 and May 31, 2022)**.").

b. The True-Up Process Should Not Allow Mystic to Recover Costs for CWC and Should Cap Recovery for Certain Labor Costs and O&M as a Whole.

The true-up adjustment should not allow Mystic to recover costs that it has not demonstrated are just and reasonable. As set forth in the NESCOE Revisions, there are several categories of such costs for which Schedule 3A should explicitly limit recovery.[227] The Commission should direct Mystic to adopt these changes for the reasons set forth below.

c. Recovery of CWC Should Be Disallowed.

Sections I.A.1.a.iii and I.B.1.a.ii, *supra*, discuss why CWC should be set to zero dollars for both the Mystic Units and EMT. The NESCOE Revisions apply this limitation to Schedule 3A.[228]

d. Overtime Labor Expenses Should Be Capped.

Mystic's proposed true-up adjustment fails to include any parameters or limitations on overtime labor expenses. Ms. Cannady explained in her testimony why this is inappropriate and could result in excessive rates.[229] As a starting point, Ms. Cannady compared Mystic's projected overtime labor expenses for the Mystic Units, 35.78%, with the overtime rates of three comparable fully-integrated utilities operating in Texas over a four-year period.[230] These utilities, which operate gas-fired generation resources similar to Mystic 8 & 9, had average overtime rates of 15.55%.[231] Mystic fails to demonstrate the justness and reasonableness of overtime labor rates at the Mystic Units that are more than double the rates of comparable utilities. Moreover, under

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[227] NESCOE Revisions, Attachment C at 1-2, Sections I.1-4 and conforming changes in Section I.C.

[228] NESCOE Revisions, Attachment C at 1, Section I.1. *See also id.* at 2, 4-7, 9, Sections I.A, C.1.i, C.2.ii, C.3.ii, C.4.i, and C.5.i (deleting "one eighth O&M cash working capital allowance").

[229] Cannady Testimony, Exh. NES-010 at 13.

[230] *Id.; see also* Exh. NES-014 at 3.

[231] Exh. NES-010 at 13 (citing NES-013 at 2 (Schedule CTC-2)).

Mystic's proposal in Schedule 3A, these rates would be unbounded by any limitations, creating the potential for even higher overtime labor expenses as part of the true-up.

As Ms. Cannady explained at the hearing, Mystic's attempts to differentiate between labor costs in Massachusetts and those costs in Texas or elsewhere[232] is unavailing. Differences in base salaries from state to state is not the issue. Mystic's focus on such differences is a distraction. Ms. Cannady's recommendation is based on the overtime being paid as a *percentage of base payroll*.[233]

Mr. Heintz also argued against a cap based on concerns that this would force Mystic to hire more operators, which he asserted would increase base labor costs.[234] But Mr. Heintz did not grapple with the lopsided overtime rates for the Mystic Units compared with the average overtime rates of comparable resources. As Ms. Cannady demonstrated, Mystic already pays significantly more in overtime rates to its employees than similarly situated utilities pay. Mr. Heintz provided no evidence to support his conclusion that a cap on existing high overtime pay will necessitate the hiring of additional employees, or, tellingly, how many new employees would be needed.

Ms. Cannady recommended that overtime labor expenses for the Mystic Units and EMT be capped at 21% of base pay. This recommendation is based on two factors. First, it is set to the highest annual overtime percentage that the comparable utilities Ms. Cannady analyzed had reported.[235] Second, based on the 2017 actuals that Mystic provided for EMT, **[BEGIN**

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[232] Tr. 1724:1-1726:2.

[233] Tr. 1724:12-25.

[234] Heintz Rebuttal Testimony, Exh. MYS-0037 at 20:5-6.

[235] Cannady Testimony, Exh. NES-010 at 14:5-6.

CUI/PRIV-HC] [redacted] **[END CUI/PRIV-HC]**.[236]

Section I.2 of the NESCOE Revisions incorporates this reasonable limitation on overtime labor expenses into Schedule 3A.[237] The Commission should require that Mystic adopt this provision.

e. The Commission Should Require Limitations on Incentive Pay and Disallow Incentive Pay Based on Financial Performance.

Mystic would like to punt to the true-up process any scrutiny regarding consumer obligations to fund employee bonus payments. The Commission should reject this approach and instead set clear guidelines for recovering incentive pay during the cost-of-service period and direct the inclusion of these guidelines in Schedule 3A.

First, the Commission should cap incentive pay at 13.3% of base pay for employees of the Mystic Units and EMT. This is a reasonable limitation. While Mystic's incentive pay rate (15.30%)[238] is based on the second highest percentage of bonus payments to employees of the Mystic Units over the last six years,[239] a 13.3% rate represents a more reasonable standard: the average incentive payments to these employees over the same period.[240]

Second, the Commission must disallow incentive pay that is based entirely on financial performance. Ms. Cannady explained that such pay "included in cost-of-service rates should be based on performance measures that benefit those using the utility services" and not based on

236 *Id.* at 6-7; *see also* Exh. NES-014 at 2.

237 NESCOE Revisions, Attachment C at 1.

238 Heintz Rebuttal Testimony, Exh. MYS-0037 at 20:16.

239 Cannady Testimony, Exh. NES-010 at 14:16-19.

240 *Id.* at 18:16-17. *See also* Exh. NES-013 at 4-5, 7; Exh. NES-015; Exh. NES-016; Exh. NES-017.

measures that solely benefit shareholders.[241] Mystic's recovery of bonus payments that are divorced from ratepayer benefits is contrary to clear Commission precedent.[242] While the Commission has indicated that certain incentive payments may be appropriate for inclusion in cost-of-service rates, those payments were shown to have a connection to "quality" utility services provided "at reasonable costs."[243] That standard is, by definition, not met when bonus payments are made solely on the basis of financial performance for the company.[244] As Ms. Cannady stated, a company is free to provide those bonuses, just not out of consumers' pockets.[245]

The Commission should require that Mystic adopt the limitations on incentive pay reflected in the NESCOE Revisions.[246]

f. Total O&M Expenses Should Be Capped.

Ms. Cannady explained that "Mystic has already escalated its O&M costs to take into account anticipated annual increases and has provided capital amounts that are based on specific expected projects."[247] There is no mechanism under Mystic's proposed Schedule 3A to protect

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241 *Id.* at 15:15-18.

242 *Public Serv. Comm'n v. FERC*, 813 F.2d 448, 456 (D.C. Cir. 1987) (finding that FERC acted permissibly in applying a policy that presumed disallowance of cost recovery relating to certain advertising that does not provide consumer benefit); *Trunkline Gas Co.*, 90 FERC ¶ 61,017 at 61,064 (2000) (disallowing cost recovery for charitable contributions because they are "primarily for the benefit of company shareholders" and insufficiently related to the utility service provided). *Accord Mountain States Tel. & Tel. Co. v. F.C.C.*, 939 F.2d 1035, 1043 (D.C. Cir. 1991) ("it is a legitimate aim of rate regulation to protect ratepayers from having to pay charges unnecessarily incurred . . . of whatever sort.").

243 *NRG Energy, Inc. v. Entergy Servs., Inc.*, 126 FERC ¶ 61,053 at P 33 (2009).

244 Mr. Heintz seeks to preserve the recovery of bonus payments on the premise that ratepayers benefit from increased sales through reduced costs. Heintz Rebuttal Testimony, Exh. MYS-0037 at 21:10-14. While increased sales could provide an ancillary consumer benefit, the bonus payments Mr. Heintz discusses are nonetheless being made on the basis of financial benefit *to the company* rather than the benefit to those using the utility service.

245 Cannady Testimony, Exh. NES-010 at 17:14-16; Tr. 1734:20-24.

246 NESCOE Revisions, Attachment C at 1, Section I.3 and conforming changes in Section I.C.

247 Cannady Testimony, Exh. NES-010 at 29:20 – 30:1-2.

consumers against further, unexpected cost escalations or to incentivize Mystic to contain costs. The Commission should require Mystic to adopt a reasonable limitation on O&M cost recovery, such as the 2% cap that Ms. Cannady has recommended. This 2% cap exceeds the average fluctuations in O&M costs for Mystic 8 & 9 between 2013 to 2017, 0.54%,[248] and is modeled on a similar limitation under Indiana law.[249]

Inclusion of a cap on total O&M costs, as reflected in the NESCOE Revisions, will impose cost discipline on Mystic and help to prevent excessive costs passed through to consumers under the Agreement.[250]

g. Mystic Attempts to Limit the Inputs Subject to the True-Up Filings Based on a Misreading of the Hearing Order.

Mystic seeks to restrict its obligation to provide cost support and prefers to true-up solely with respect to: (1) capital expenditures, (2) O&M expenses, (3) administrative and general expenses, and (4) taxes other than income. However, the Commission imposed no such restriction, a fact which Mr. Heintz, the architect of Schedule 3A, acknowledged on cross-examination.[251] Instead, the Commission discussed in broader terms the costs that would be subject to the true-up process.[252] That the Commission listed some items to be included in the true-up should not be read as an exclusion of others.[253] While it may be convenient and profitable for Mystic to narrow the inputs subject to the true-up mechanism, rates should reflect actual prudently incurred costs.

[248] *Id.* at 30-31; Exh. NES-013 at 6 (Schedule CTC-4); Exh. NES-014 at 6.

[249] Cannady Testimony, Exh. NES-010 at 30:5-16.

[250] NESCOE Revisions, Attachment C at 1-2, Section I.4 and conforming changes in Section I.C.

[251] Tr. 311:4-6.

[252] Hearing Order at P 20.

[253] *See id.* at n. 30 (O&M and administrative and general expenses "should *also* be subject to the true-up mechanism.") (emphasis supplied); *accord*, *id.* at P 20 (". . . we direct the participants to present evidence regarding the appropriate design of the true-up mechanism in the Agreement.").

The NESCOE Revisions remove the artificial restrictions that Mystic seeks to place on the true-up process. It ensures that Mystic will provide support for all components of rate base for which it seeks recovery from consumers under the Agreement, rather than a subset of rate base.[254] Federal income taxes, including any refunds for excess deferred income taxes due to changes in federal law, are also explicitly listed as a component subject to the true-up process. In addition, interested parties will have the opportunity to review the true-up adjustments for this broader range of cost components and be able to challenge them under the protocols contained in Schedule 3A.

The Commission should reject Mystic's attempt to limit the inputs that are subject to the true-up process and should instead direct Mystic to adopt the changes set forth in the NESCOE Revisions.[255]

h. The Commission Should Direct Other Key Changes to Schedule 3A to Enhance Transparency and Clarity and the Ability of Interested Parties to Review and Challenge Mystic's Asserted Costs.

i. Mystic's proposal erects an unnecessary barrier to information exchange.

Mystic includes multiple layers of limitations in its proposed Information Exchange Procedures. NESCOE requests a single substantive change to this information exchange process. The intent of this change is to eliminate an obstacle to interested parties receiving information during a more informal part of the cost review process and potentially obviate the need for challenges later in the process. In both Sections II.3.A and II.3.B, as currently drafted, the information exchange and document requests are limited to "what *is necessary* to determine"

[254] Testimony that FERC Trial Staff sponsored in this proceeding supports this change. *See* Exh. S-0034 at 2:13-19, 5:12-17.

[255] NESCOE Revisions, Attachment C at 2, 4-9 (setting forth changes in Sections I.A and I.C that clarify the broader costs to be included in the true-up filings).

various items and criteria related to the true-up filing.[256] There is no sound reason to layer on this restriction and leave room for dispute. The Commission should direct that Mystic amend these sections to provide appropriate latitude to consumer-interested parties and others seeking information through this process. As reflected in the NESCOE Revisions, the information exchange and document requests should instead be limited to "what *may be reasonably* necessary to determine . . . ."[257]

This change is consistent with recent formula rate protocols pending before the Commission as part of an offer of settlement filed by a broad coalition of New England transmission owners, NESCOE, New England state public utility commissions, and various other New England state governmental agencies.[258] The New England Formula Rate Settlement, which included changes to the formula rate as well as the development of protocols, was the culmination of two-and-one-half years of negotiations among numerous parties with diverse interests. In stark contrast, Mystic developed Schedule 3A unilaterally and without the initial benefit of stakeholder input. The language Mystic proposes could result in customers having to demonstrate that certain information is necessary, without having the benefit of that information. This is both illogical and more onerous than the language in the New England Formula Rate Settlement and the Commission should direct Mystic to make the change NESCOE recommends.

ii. Revisions to the challenge procedures.

The Commission should direct three changes to the Challenge Procedures in Section II.4 of Mystic's proposed Schedule 3A. First, it should require the addition of language in Section

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[256] Exh. MYS-0052 at Section II.3.A and Section II.3.B (emphasis supplied).

[257] NESCOE Revisions, Attachment C at 13-14, Sections II.3.A and II.3.B (emphasis supplied).

[258] Joint Offer of Settlement, Docket Nos. ER18-2235-000, *et al.* (filed Aug. 17. 2018) ("New England Formula Rate Settlement").

II.4.A to eliminate Mystic's unreasonable restrictions on the filing of formal challenges.[259] Ms. Cannady further noted that this restriction "could unintentionally encourage multiple, duplicate informal challenges from parties seeking to preserve the right to file a formal challenge later."[260]

Second, the Commission should direct Mystic to delete Section II.4.D.[261] The scope of informal and formal challenges is already set forth in Sections II.4.B and II.4.C. Ms. Cannady recommended striking the scope limitations in Section II.4.D because they are "redundant and potentially confusing" when considering other sections of the document.[262] Mr. Heintz's response to a question seeking to ascertain the value of Section II.4.D compounds this confusion and inaccurately stated that there are items listed in Section II.4.D that are not already captured in Section II.4.C.[263]

Third, interested parties should have until November 15th, rather than October 15th, to submit a formal challenge with the Commission.[264] Ms. Cannady noted correctly that "the annual process that Mystic has proposed is generally too compressed for interested parties to effectively engage in information exchange and challenge procedures."[265] Extending the deadline for formal challenges by one month would provide additional time for parties to

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[259] NESCOE Revisions, Attachment C at 15-16, Section II.4.A.

[260] Cannady Testimony, Exh. NES-010 at 33:1-3. NESCOE's proposed language is modeled on a provision included in the New England Formula Rate Settlement.

[261] NESCOE Revisions, Attachment C at 19.

[262] *Id.* at 34:7-9.

[263] Tr. 321:13-25 – 322:1 ("Q: And then looking at MYS-0051 at page 21, looking at section II(4)(D), there's a list of eight items under D on that page. And I just want to confirm that each of those items is also intended to be included under II(4)(C), which is at page 19 carrying over to 20.

A: I think C is setting out the requirement that must be met, and D is limiting the informal and formal challenges to issues relating to that. And those three tests that are in C are included in D. But D also includes others which are -- where there's an account exchange, there's a -- data is not properly recorded, the proper application is at -- the methodology in section 3 is not followed, the accuracy of the data, and the prudence of the expenditures. So it goes beyond what is in C.").

[264] NESCOE Revisions, Attachment C at 19, Section II.4.E.

[265] Cannady Testimony, Exh. NES-010 at 31:6-8.

consider Mystic's responses to informal challenges and whether a formal challenge is warranted. It also would provide additional time to prepare a formal challenge consistent with the long list of requirements contained in Section II.4.C. In making this request for a one-month extension, NESCOE notes that it is no longer seeking to accelerate the date by which Mystic has to make its annual update filings, and will agree to the April 1st date Mystic has proposed.[266]

D. The Agreement Is Unjust and Unreasonable Without a Clawback Mechanism, and the Commission Should Direct Mystic to Adopt NESCOE's Balanced Approach.

The Agreement must include a properly structured "clawback" mechanism that achieves the objective of protecting consumers' economic interests while not discouraging an otherwise efficient generator from continuing to operate, to ratepayers' ultimate detriment. Without an appropriate clawback, Mystic will reap windfall profits at ratepayers' expense if the Mystic Units and/or EMT continue operations after the term of the Agreement by pocketing the substantial capital investments consumers funded during the cost-of-service period. The Commission must act where Mystic and ISO-NE have not: the conspicuous absence of a clawback provision in the Agreement is another striking example of the outcome of two-party negotiation of a contract where neither party exercised a responsibility to the consumers paying the bill.[267] NESCOE has proposed a fair and balanced proposal to address the Agreement's shortcoming and respectfully asks the Commission to direct Mystic to adopt this approach. Connecticut does not support NESCOE's clawback design and may address this issue in a separate pleading.

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[266] Ms. Cannady had recommended an early March 1 filing date. *See* Exh. NES-020 at 3-8, Section I.C. NESCOE recognizes the concerns that Mr. Heintz raised regarding the timing of the process in light of Exelon's and Mystic's timelines for filing audited financial date (Heintz Rebuttal Testimony, Exh. MYS-0033 at 29:15-22 – 30:1) and now proposes to retain the April 1 filing date.

[267] *See supra* at pp. 2-7 (discussing the lack of obligation of any party to the Agreement to consumer interests).

1. Clawback Objectives

Clawback mechanisms address the possibility that a cost-of-service resource will reenter the competitive wholesale markets after a cost-of-service period has concluded. A clawback requires the resource to repay consumers for capital expenditures (and potentially other costs)[268] that consumers paid for during the cost-of-service period.[269] This mechanism protects consumers and promotes the future competitiveness of the wholesale market, preventing "an inequitable and inappropriate outcome for consumers" and addressing "the unfair competitive advantage that a resource would have over other resources" that lacked a "dedicated revenue stream for capital expenditures and repairs funded by consumers."[270]

The Commission has not precluded cost-of-service resources from reentering the competitive market, but it has stated that these resources should "not use [cost-of-service] agreements to continue to operate while they wait for market conditions to improve."[271] In addition, while the Commission generally disfavors resources moving between cost-of-service and market-based rate structures,[272] it has also expressed concern regarding the design of a clawback provision that could potentially "discourage an otherwise efficient generator from continuing to operate to the detriment of customers."[273]

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268 *See, e.g.*, *Midcontinent Independent System Operator, Inc.*, 161 FERC ¶ 61,059 at PP 54-60 (2017) ("MISO Order") (directing that clawback provision should include refunds for both capital expenditures and repairs providing significant benefits beyond the cost-of-service period).

269 Bentz Testimony, Exh. NES-001 at 23:11-13. *See, e.g.,* Midcontinent Independent System Operator, Inc., FERC Electric Tariff, Module C, § 38.2.7e ("MISO Clawback"); PJM Interconnection, L.L.C., Intra-PJM Tariffs, Open Access Transmission Tariff, § 118 ("PJM Clawback"); New York Independent System Operator, Inc., Market Administration and Control Area Services Tariff, Rate Schedule 8, § 15.8.7 ("NYISO Clawback").

270 Bentz Testimony, Exh. NES-001 at 23:14-19.

271 *New York Independent System Operator, Inc.*, 161 FERC ¶ 61,189 at P 84 (2017) ("*NYISO* Order"), *order on clarification & reh'g*, 163 FERC ¶ 61,047 (2018).

272 *See, e.g.*, *NYISO* Order at P 83.

273 *Id*. at P 85 (quoting *New York Independent System Operator, Inc.*, 155 FERC ¶ 61,076 at P 127 (2016)).

To NESCOE's knowledge, no party to this proceeding has opposed the inclusion of a clawback mechanism as part of the cost-of-service arrangement at issue. In its initial filing, Mystic volunteered that if the Mystic Units remained operational past the Term, it was "willing to provide a 'clawback' process to refund certain capital expenditures incurred during the reliability term" and that "this item could be addressed in the settlement process if this matter is set for hearing and settlement."[274] Mystic has likewise expressed openness to a clawback process in connection with capital expenditures for EMT.[275]

The need to incorporate a clawback into the Agreement is acute given current New England activities. ISO-NE is in the process of developing a long-term solution to fuel security concerns to comply with the Commission's July 2, 2018 order in Docket Nos. ER18-1509-000 and EL18-182-000.[276] In that order, the Commission directed a compliance filing by July 1, 2019 (or, alternatively, ISO-NE must show cause why its Tariff is just and reasonable). ISO-NE has noted that it is "not precluded from evaluating, as part of the market design process for a market-based fuel security solution, the potential value of the Mystic units following termination of the Mystic COS Agreement."[277] Moreover, according to ISO-NE, the Commission could allow Mystic 8 & 9 to continue operations beyond the cost-of-service period pursuant to current Tariff provisions.[278] Mr. Schnitzer acknowledged the possibility of the Mystic Units remaining in operation past 2024, stating that such an outcome "will likely be because the fuel security fix

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274 Hearing Order at P 15.

275 Exh. NES-004 at 3.

276 *ISO New England Inc.*, 164 FERC ¶ 61,003 (2018) (*reh'g pending*) ("ISO-NE Tariff Waiver Order"). *See also* Winter Energy Security Improvements: Market-Based Approaches; Problem Statement and a Conceptual Approach to Address the Problem, New England Power Pool Markets Comm. (Oct. 10, 2018), available at https://www.iso-ne.com/committees/markets/markets-committee.

277 Exh. NES-003 at 9.

278 *Id*. at 8.

provides sufficient market revenue for continued operation to be economic."[279] In addition, such a "fuel security fix" could provide potential business opportunities to EMT, encouraging continued operations of the LNG terminal beyond the cost-of-service period and possibility without either of the Mystic Units remaining operational.[280]

2. NESCOE's Proposed Clawback Mechanism

As Mr. Bentz explained, NESCOE's proposed clawback approach "ensures that consumers are repaid within a reasonable time frame while, at the same time, reducing barriers to market participation if a resource proves to be efficient and competitive in the marketplace."[281] NESCOE's proposed clawback is reasonable by design because it addresses the Commission's concern that a clawback might "discourage an otherwise efficient generator from continuing to operate to the detriment of customers,"[282] imposing potentially hundreds of millions of dollars in additional costs onto ratepayers to meet resource adequacy needs through new resources that are not needed.

Mr. Bentz developed NESCOE's proposed clawback mechanism to reflect these considerations and sought to balance the interests of both consumers and Mystic. He adapted the proposed clawback to address the specific Agreement and resources at issue in this proceeding.

NESCOE's recommended clawback provision is provided as part of Attachment A herein.[283] It would be a new Section 12.1 of the Agreement. Mr. Bentz explained in his testimony the features of the mechanism:[284]

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279 Schnitzer Rebuttal Testimony, Exh. MYS-0053 at 37:9-11.

280 *See* Bentz Testimony, Exh. NES-001 at 23:2-4.

281 *Id*. at 27:5-8.

282 *NYISO Order* at P 85 (quoting *New York Independent System Operator, Inc.*, 155 FERC ¶ 61,076 at P 127 (2016)).

283 Attachment A at 37-38.

- The clawback would apply to Mystic 8 & 9 and EMT;

- The clawback amount would be based on any capital expenditures made during the cost-of-service period and costs for repairs that provide significant benefits beyond the end of that period. (This would be determined by the Owner or its Lead Market Participant and verified by an independent entity);

- Mystic would calculate a refund amount equal to the sum of: (1) actual cost of capital expenditures paid, less depreciation as determined under generally accepted accounting principles,[285] plus interest at the FERC-approved rate, and (2) the actual cost of repairs that provide significant benefits beyond the cost-of-service period, pro-rated for the benefit received during the cost-of-service period, plus interest at the FERC-approved rate;

- No less than three months prior to the end of the Agreement term, Mystic must file with the Commission the refund amount calculation and a list of the capital expenditures and repairs included in the calculation. Mystic must also include in the filing a list of capital expenditures and repairs made during the cost-of-service period that it did not include in the refund amount calculation. (The time period is intended to be close enough to the end of the cost-of-service period to ensure that the refund amount will be known prior to the Mystic Units or EMT reentering the market and would provide states, customers, and other interested parties sufficient time to review the calculation.);

- The refund amount would be amortized over a four-year straight-line period (thus requiring 1/48th of the total refund for every month the triggering conditions are not met);

- The clawback termination triggering condition for Mystic 8 & 9 would be when their interconnection rights are terminated; and

- The clawback termination triggering condition for EMT would be if and when the facility has not vaporized gas for any continuous three-month period.

NESCOE's approach borrows from some of the concepts reflected in the clawback provisions that other regions have implemented, but it departs in material respects to tailor the mechanism to the unique circumstances presented in this proceeding. For example, the Midcontinent Independent System Operator, Inc. ("MISO"), PJM Interconnection, L.L.C.

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284 Bentz Testimony, Exh. NES-001 at 25-26; *see also* Exh. NES-002 at 3-4.

285 In response to a data request, Mr. Bentz clarified that his recommendation should be modified by substituting "as determined under generally accepted accounting principles" for "as approved in the Agreement." He noted that this clarifying change should further be reflected in Exh. NES-002. *See* Exh. MYS-0169 at 1.

("PJM"), and the New York Independent System Operator ("NYISO") each employ different payback periods. Mr. Bentz did not adopt any of these approaches and instead has recommended adopting a four-year payback period in this case. This most closely resembles the NYISO Clawback, which sets the refund period to the shorter of 36 months or twice the duration of the applicable cost-of-service agreement.[286] Mr. Bentz viewed a 48 months refund period—twice the duration of the Agreement—to be most appropriate given his review of "the proposed capital expenditures and expected lives of the facilities in connection with the Agreement."[287] The recommended refund period—as well as other features of the clawback—are designed not to impose an overly burdensome administrative process onto ISO-NE, Mystic, and others involved in the settlement of refunds.

In addition, given the Commission's concern that a clawback could "discourage an otherwise efficient generator from continuing to operate to the detriment of customers,"[288] NESCOE sought in its clawback design to avoid the imposition of an unduly high hurdle to the resource reentering the market. At the same time, NESCOE sought to avoid extending the payback period over too many years in order to be fair to ratepayers, who should be repaid as soon as is reasonably practicable. Moreover, due to consumer attrition, an unreasonably long payback period could deprive some ratepayers of all or part of their refunds.[289]

While a clawback can be designed to require repayment of a broader category of costs, including return on equity, NESCOE's clawback provision is limited to capital expenditures and

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[286] NYISO Clawback at §§ 15.8.7.1 and 15.8.7.2.

[287] Bentz Testimony, Exh. NES-001 at 26:21-22.

[288] *NYISO Order* at P 85.

[289] *Cf. Allegheny Generating Co.*, 69 FERC ¶ 61,439, at 62567 (1994) ("to avoid inter-generational inequities among customers, utilities are expected to recover costs on a *pro rata* basis from the customers taking service over the life of the asset).

repairs that provide a significant benefit beyond the cost-of-service period. This is modeled on the MISO Clawback. NESCOE recognizes that different regions may design clawbacks to meet unique circumstances; here, NESCOE views its recommended approach as more closely aligning with consumer interests under the circumstances of this Agreement. For the same reasons discussed above regarding the payback period, NESCOE believes that a clawback that requires refunds of all positive cash flows or above market rates earned during the cost-of-service period would present an overly high hurdle to market reentry. As with the payback period, this could cause an efficient unit to retire prematurely, leaving consumers without any refunds *and* being saddled with the substantial costs of one or more new resources needed for resource adequacy.

A more aggressive clawback may appear at first glance to better protect consumers' economic interests—at least in the near-term—but, in practice, its trade-offs described above may place ratepayers in a worse economic position. Similarly, consumers are disadvantaged by a clawback design that is overly generous to the resource or one that extends the repayment period too far into the future. The Commission should reject more extreme clawback approaches and direct Mystic to incorporate into the Agreement NESCOE's balanced approach to a clawback mechanism.

3. Mystic's Triggering Exclusions Are One-Sided, Unfair to Consumers, and Give Mystic a Competitive Advantage Over Other Market Participants.

While Mystic expressed an early openness to applying a clawback mechanism to costs recovered under the Agreement,[290] its position has apparently evolved to include several caveats. Mystic now seeks to narrow the triggering events for a clawback, substantially undercutting the

[290] Transmittal Letter at 16.

conditions under which it would apply.[291] The Commission should reject this approach that advantages shareholders over ratepayers in favor of NESCOE's approach that seeks to balance interests.

Mystic's witness, Mr. Schnitzer, begins his criticism of NESCOE's proposal by stating that it "makes no attempt to distinguish circumstances where the return of a generator to the market is not toggling."[292] This is correct. Mr. Schnitzer's focus on the clawback may be in providing "a disincentive for generators to try to 'toggle' back and forth to get the 'higher' of cost of service or market revenues."[293] That is not, however, NESCOE's objective. As Mr. Bentz concisely explained: NESCOE's balanced approach to the clawback is intended to "ensur[e] that consumers are repaid within a reasonable time frame while, at the same time, reducing barriers to market participation if a resource proves to be efficient and competitive in the marketplace."[294] The Commission has articulated this same concern regarding the implementation of a clawback mechanism that could drive an efficient unit to retire rather than reenter the market to the benefit of consumers.[295]

Mr. Schnitzer then asserts that the NESCOE proposal should be modified to exempt Mystic from a clawback under two circumstances. First, if ISO-NE implements market rules valuing fuel security and if Mystic is eligible for this "market fuel security compensation," Mr. Schnitzer concludes that Mystic's reentry into the market should not trigger the clawback.[296] He states that Mystic's decision to exit the Mystic Units from "the market was caused by an

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291 Schnitzer Rebuttal Testimony, Exh. MYS-0053 at 36-38.

292 *Id*. at 36:23 – 37:1-2.

293 *Id*. at 36:14-16.

294 Bentz Testimony, Exh. NES-001 at 27:5-8.

295 *See supra* note 282.

296 Schnitzer Rebuttal Testimony, Exh. MYS-0053 at 37:2-21.

unpriced fuel security constraint in the ISO-NE capacity and/or energy markets – in short, a market failure."[297] Mr. Schnitzer states that "[i]f Mystic does remain operational at the conclusion of the Mystic Agreement, it will likely be because the fuel security fix provides sufficient market revenue for continued operation to be economic."[298] He reasons that "a claw back would serve no useful service and could actually be an impediment to achieving the region's fuel security requirements" because the clawback "turns a sunk cost (already incurred capital investment) into a 'to go' cost from the perspective of Mystic."[299] Mr. Schnitzer complains that "market revenues not only would have to cover all of the real 'to go' costs of continued operation, including risk compensation, but they also would have to fund the refund obligation under the claw back."[300]

As an initial matter, Mystic's proposed exclusion from the clawback contravenes Commission policy. Mystic cannot leverage the Agreement to continue operating the Mystic Units while it bides it time "for market conditions to improve."[301] The triggering exclusion, directly connected to ISO-NE's implementation of new Commission-ordered market rules that may provide additional compensation to Mystic, seeks to do exactly that. There is no basis for the Commission to take such an explicit departure from its precedent.

Mr. Schnitzer also leaves out a key detail in his summation. If no "market failure" ever existed, and Mystic did not receive a cost-of-service Agreement, it alone would have the obligation to fund all of the capital expenditures for the Mystic Units. This is the same obligation that all market participants assume in the competitive market. It is inaccurate to

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[297] *Id.* at 37:2-4.

[298] *Id.* at 37:9-11.

[299] *Id*. at 37:11-15.

[300] *Id*. at 37:16-18.

[301] *NYISO* Order at P 84.

characterize the repayment of these expenses as a barrier to entry: these "to go" costs are the cost of being in business, as they are for all resources in the market today. To the extent these costs are too high a hurdle for Mystic 8 & 9, as Mr. Schnitzer appears to suggest, this would indicate that the resources are not, in fact, competitive and should indeed retire.

The second basis Mr. Schnitzer provides for an exemption from a clawback is if the Mystic Units are "still needed for fuel security reasons and the Mystic Agreement needs to be extended."[302] The Commission should likewise reject this one-sided plea. In essence, Mystic is asking to be free to earn positive cash flows funded by consumers, while consumers are forced to wait for any refunds, if any, that they might receive. It would be unjust and unreasonable to allow Mystic to profit from the capital expenditures that consumers fund during the cost-of-service period only to extend these profits without any payback, or at the very least some consideration in any future cost-of-service agreement. Consumer interests are not subordinate to shareholder interests, and the clawback should not be structured as if they are.

The Commission should reject Mystic's request to narrow the clawback mechanism. NESCOE's approach places parameters around the clawback that balances interests and warrants approval as proposed.

II. CERTAIN TERMS AND CONDITIONS OF THE AGREEMENT HAVE BEEN SHOWN TO BE UNJUST, UNREASONABLE, AND UNDULY DISCRIMINATORY.

A. The Commission Should Provide Meaningful Opportunities for Oversight of the Mystic Units and EMT During the Cost-of-Service Period.

Despite the Agreement's explicit shift of costs and risks away from shareholders and onto consumers, and Exelon's acceptance of obligations regarding an LNG terminal that are outside its traditional expertise, Mystic resists increased oversight of the Mystic Units' and EMT's

302 Schnitzer Rebuttal Testimony, Exh. MYS-053 at 37:22-23 – 38:1.

operations and expenses during the cost-of-service period.[303] NESCOE has identified throughout this brief numerous instances in which Exelon, through the Agreement, shifts risks and costs unreasonably and inappropriately to consumers. This is the outcome of a negotiation process in which neither Exelon nor ISO-NE, the only parties to the Agreement, considered consumer cost implications to be within their purview. Because the Agreement may impose hundreds of millions of dollars in costs on consumers, its execution requires oversight commensurate with the level of consumer risk and cost exposure. Intervenors' concerns about oversight cannot be lightly pushed aside. NESCOE urges the Commission, at minimum, to require meaningful opportunities for states and other consumer-interested parties to review, assess, and provide input on the operations and costs in connection with the Mystic Units and EMT.

It is imperative that the Commission react to this deference on consumer costs issues with vigorous oversight of the Agreement's execution throughout its term. To that end, NESCOE believes there is practical value to the Commission and consumers in providing opportunities for states and others to assist the Commission in reviewing the implementation of this complex, first-of-its-kind Agreement. This cost-of-service arrangement is complex, involving scheduling of LNG cargoes, third-party fuel sales, performance penalties, and numerous contractual rights and obligations. Contrary to Mystic's claim, ISO-NE's *right* to audit Mystic falls short of the oversight required under the circumstances of this cost-of-service arrangement and the protections consumers require.[304] The incentive structure in the Agreement[305] is also not a sufficient proxy for oversight and the Commission should not interpret it as such.

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303 *See, e.g.,* Berg Rebuttal Testimony, Exh. MYS-0025 at 10:7-23 – 12:1-5, 14:3-23 – 15:1-5.

304 *Id*. at 14:4-5.

305 *Id*. at 10:18-20.

To be clear, NESCOE does not seek a process through which to substitute its or other parties' judgment for Exelon's judgment. Its primary interest is in understanding Exelon's operational business decisions and future practices, such as LNG cargo delivery, that may cause consumers to incur substantial incremental costs. Particularly in those areas that are novel to generator cost-of-service agreements, where Exelon has scant experience and consumers are assuming the risk for its decisions, careful regulatory scrutiny is warranted and necessary to consumer confidence about cost containment. Indeed, NESCOE's recommended Reliability Charge approach (*see supra*, Section I.B.2.a) is driven in part by NESCOE's concern about actions such as scheduling LNG cargoes and managing third-party fuel sales, which have significant consumer cost implications. As discussed in Section I.B.2.a above, the Reliability Charge model mitigates the need for oversight over the EMT because it provides Exelon with the incentive to manage that facility as efficiently as possible.

In addition to the Reliability Charge structure, the Commission should consider providing states and other parties, as appropriate, with opportunities to monitor the operations and costs of the Mystic Units and EMT during the cost-of-service period. One path to accomplish this is the Connecticut Parties' proposal for management audits.[306] NESCOE urges the Commission to require ongoing opportunities for states and other consumer-interested parties to review timely information on the transactions Mystic and its affiliates undertake in furtherance of the cost-of-service arrangement.

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[306] *See* Exh. CT-010 through Exh. CT-017.

III. THERE ARE OTHER ASPECTS OF THE PROPOSED RATE TO BE COLLECTED UNDER THE MYSTIC AGREEMENT THAT ARE NOT JUST AND REASONABLE, AND ADDITIONAL TERMS AND CONDITIONS OF THE MYSTIC AGREEMENT THAT SHOULD BE ADOPTED.

A. The Commission Should Require Changes to the Agreement to Safeguard Consumers and Should Disallow Costs that Mystic Has Not Demonstrated are Just and Reasonable.

1. The Agreement Should Be Modified to Enhance Commission Oversight and Consumer Protections, Ensure that Excess Performance Payments Accrue to Consumers, and Better Align with the Objectives of the Agreement.

In his testimony, Mr. Bentz identified the need for revisions to the Agreement to clarify how it may be extended beyond the two-year Term.[307] Mr. Bentz recommended that any extension should be subject to Commission approval, with the opportunity for states and others to comment as part of the proceeding.[308] To conform with this recommendation, Mr. Bentz suggested deleting Section 2.2.1[309] (a new provision not included in the *pro forma*) and modifying Section 2.2.[310] Mystic has agreed with NESCOE that Section 2.2.1 should be deleted and that Section 2.2 be changed to require that "ISO-NE seek Commission approval to extend the Mystic Agreement beyond" the two-year term.[311] While NESCOE expects that Mystic will seek to refile the Agreement to reflect these and other changes as part of its compliance with a pending Commission order, the Commission should ensure that NESCOE's proposed modifications to Sections 2.2 and 2.2.1 are reflected in any further compliance filing.[312]

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[307] Bentz Testimony, Exh. NES-001 at 11-13; Exh. NES-002 at 1.

[308] *See* Exh. NES-001 at 12:13-18.

[309] Exh. MYS-0080 at 11.

[310] *Id*. at 11-12; Exh. NES-002 at 1; *see* Exh. MYS-0080 at 11 (Section 2.2).

[311] Berg Rebuttal Testimony, Exh. MYS-0025 at 4:18-22.

[312] These changes are reflected in Attachment A at 11.

In addition, the Commission should direct a change to Section 4.4.3 of the Agreement that Mystic has proposed to clarify its and ISO-NE's intent in negotiating the provision (addressing the opportunity cost adder). This change is discussed in Section I.B.3.a.ii, above.

a. The Commission Should Clarify that Excess Positive Capacity Performance Payments Flow to Consumers.

In the course of cross examining witnesses for Mystic and ISO-NE, NESCOE identified what appeared to be an oversight in the Agreement with potential significant consumer cost implications. Section 3.6 of the Agreement provides, in pertinent part, that:

> The Resources shall be subject to negative Capacity Performance Payments and eligible for positive Capacity Performance Payments consistent with other Resources with Capacity Supply Obligations; provided, however, that positive Capacity Performance Payments shall be used solely as a credit against negative Capacity Performance Payments and shall not otherwise accrue to the benefit of the Resources, but net negative Capacity Performance Payments shall affect the amount of the Revenue Credit.[313]

In other words, if the Mystic Units over-perform during scarcity events, the positive Capacity Performance Payments are used to offset any negative Capacity Performance Payments. Section 3.6 is clear, however, that any excess positive Capacity Performance Payments "shall not . . . accrue to the benefit" of the Mystic Units. As Mr. Schnitzer succinctly stated in response to cross examination, **[BEGIN CUI/PRIV-HC]** [redacted] **[END CUI/PRIV-HC]**.[314]

The Agreement is not explicit about what happens to excess bonus performance payments. Mr. Schnitzer responded in cross-examination that he **[BEGIN CUI/PRIV-HC]** [redacted]

[313] Exh. MYS-0080 at 15. In Attachment A, NESCOE revised what it believes to be an inadvertent capitalization of "Resources" in the first sentence of Section 3.6: "The Resources shall be subject to negative Capacity Performance Payments and eligible for positive Capacity Performance Payments consistent with other ~~Resources~~ **resources** with Capacity Supply Obligations . . . ." Attachment A at 16. As currently drafted, this language fails to make the Mystic Units subject to the same positive or negative Capacity Performance Payments of other resources.

[314] Tr. 881:25 – 882:1.

[redacted] **[END CUI/PRIV-HC]**.[315]

In his testimony at the hearing, Dr. Ethier explained his understanding of how net bonus performance payments that the Mystic Units earned would be settled: **[BEGIN CUI/PRIV-HC]**

> [redacted]

> [redacted]

[redacted]

> [redacted]

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[315] Tr. 883:1-7.

[316] Tr. 1141:19-25 – 1142:1-20.

[redacted] **[END CUI/PRIV-HC]**.[317]

NESCOE requests that the Commission address the lack of clarity regarding the settlement of any excess positive Capacity Performance Payments associated with the Agreement. If consumers are required to fund the Mystic Units during the cost-of-service period, any excess bonus payments should accrue to consumers (helping to offset the significant costs associated with the Agreement).

NESCOE believes that the existing language in the Agreement needs to be modified to accomplish the objective of crediting back any "unused" positive Capacity Performance Payments to consumers. NESCOE notes that Mystic is not adversely affected by this clarification since the Agreement expressly provides that excess bonus payments do not accrue to the Mystic Units. Accordingly, NESCOE respectfully asks the Commission to direct changes to the Agreement to ensure that ISO-NE credits excess positive Capacity Performance Payments as a credit to load through a reduction in the Supplemental Capacity Payment.

b. ISO-NE Should Have Greater Flexibility to Terminate the Agreement for Unavailability and Forced Outages.

Mr. Bentz recommended two changes to the Agreement to protect consumers if the Mystic Units fail to provide the service for which consumers are paying them. First, in Section 2.2.2,[318] Mr. Bentz proposed that a winter unavailability period be added (December through February of each year) as a termination trigger and that a stricter operational metric be employed by adjusting the threshold from 50% to 75%.[319] (Mr. Bentz also suggested that the term "Resource" should be made plural to clarify that ISO-NE may assess the Mystic Units' combined

[317] Tr. 1142:21 – 1143:6.

[318] Exh. MYS-0080 at 11.

[319] Bentz Testimony, Exh. NES-001 at 14-16; Exh. NES-002 at 1.

operations).[320] Second, in Section 7.1.2(b),[321] the Agreement loosens the *pro forma's* notice requirement for anticipated forced outages, increasing the threshold from ten to 25 days. Mr. Bentz recommended reinstating the ten-day requirement.[322] Both of these changes are reflected in Attachment A of this filing.[323]

NESCOE underscores at the outset two important considerations in recommending these changes. First, ISO-NE is seeking to retain the Mystic Units for fuel security, with a focus on reliability risks during the *winter months*.[324] ISO-NE has stated to the Commission "that the loss of [the Mystic Units] presents unacceptable fuel security risks" based on the potential for load shedding during the 2022-2023 and 2023-2024 *winter periods*.[325] To the extent the Mystic Units are unavailable or non-operational during the cost-of-service period, and in particular the critical winter months, consumers will pay for services they do not receive. That is not a just and reasonable outcome. As ISO-NE has acknowledged, the ability to terminate the Agreement provides ISO-NE with a mechanism to protect consumers.[326] The termination triggering provisions in the Agreement should likewise protect consumer interests.

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[320] Exh. NES-001 at 16: 14-20; NES-002 at 1. This change is consistent with ISO-NE's interpretation. Exh. NES-003 at 5.

[321] Exh. MYS-0080 at 23.

[322] Exh. NES-001 at 18-21; Exh. NES-002 at 2.

[323] Attachment A at 11, 24.

[324] *See, e.g.*, Exh. NES-003 at 2 (ISO-NE explanation that its "objectives for the agreement were to ensure that the Mystic units would have the incentive to maintain sufficient fuel on site to be available during times of critical need in the winter months.").

[325] *ISO New England Inc.*, Docket No. ER18-1509-000, Petition of ISO New England Inc. for Waiver of Tariff Provisions at 3 (May 1, 2018) (emphasis supplied); *see* ISO-NE Tariff Waiver Order at P 49 ("ISO-NE performed the Mystic Retirement Studies to evaluate operational risks associated with the retirement of Mystic 8 and 9 prior to the 2022-2023 and 2023-2024 winter periods. In these Mystic Retirement Studies, ISO-NE presented 18 scenarios covering a range of possible circumstances if Mystic 8 and 9 were to retire. Seventeen of the 18 scenarios showed that ISO-NE will deplete its 10-minute operating reserves, which is a violation of NERC reliability criteria. In addition, eight of the 18 scenarios demonstrate that ISO-NE will need to shed load.").

[326] Tr. 1130:21-24.

Second, even with modifications to the termination triggers, ISO-NE would retain its discretion to exercise its termination rights. NESCOE does not propose any changes that would alter ISO-NE's ability to use its judgment regarding whether termination is warranted under a specific set of facts or conditions.

i. Section 2.2.2

Mystic does not agree with Mr. Bentz's recommendation to revise Section 2.2.2 or Section 7.1.2(b). Regarding Section 2.2.2, Mr. Schnitzer testified that:

> While it is not entirely clear to me whether the "During any three (3) month period from December – February" language is intended to span different Commitment Periods, there is a more fundamental problem with Mr. Bentz's proposal. Section 2.2.2. was specifically negotiated in concert with the increased Capacity Supply Obligation in Winter months contained in Section 3.1. Thus, the 50 percent availability requirement was deemed reasonable in light of the fact that Mystic would incur additional Capacity Supply Obligations of nearly 300 MW in December – February. Mr. Bentz's proposal layers the additional risk of contract termination upon the bargain already negotiated by ISO-NE, in which Mystic took on significant additional capacity supply obligations in the Winter. His proposal tips the balance too far and should be rejected.[[327]]

Mr. Bentz readily acknowledged that his recommended changes to this provision increase the risk to Mystic that ISO-NE could terminate the contract.[328] The recommendation is intended to achieve a more equitable balance between shareholder and consumer interests. As drafted, Section 2.2.2 solely applies a twelve-month evaluation of the ratio of the Mystic Units' economic maximum limit to their capacity supply obligation to determine the triggering right. Under this standard, as Mr. Bentz notes, the Mystic Units "could effectively be unavailable during either of

[327] Schnitzer Rebuttal Testimony, Exh, MYS-0053 at 44:10-20.

[328] Tr. 1642:24 – 1643:2.

the two winter periods [of the Agreement] and still not trigger this clause."[329] The failure of the Agreement to account for the unavailability of the Mystic Units during the winter months, which ISO-NE has identified as the highest reliability risk, is a serious gap in the Agreement. NESCOE underscores Mr. Bentz's statement that "the Agreement has little value to consumers if Mystic is unable to operate during the winter months."[330]

Moreover, contrary to Mr. Schnitzer's assertion, the 50% availability requirement is not reasonable simply because Mystic has agreed to additional capacity supply obligations during the winter months. This enhanced obligation should not excuse Mystic from operating at only half of its economic maximum limit while continuing to receive a substantial out-of-market payment from consumers. ISO-NE has acknowledged that a "higher availability threshold for termination may . . . be warranted."[331] NESCOE has proposed such an availability requirement (75%) subject, of course, to the Commission's determination of the appropriate threshold value following its review of the record in this proceeding.

ii. Section 7.1.2(b)

The Agreement modifies the Notice of Forced Outages provision of the *pro forma*. In the *pro forma*, the resource owner must notify ISO-NE if a Forced Outage is expected to last for more than ten days. The Agreement provides substantially more favorable terms to Mystic than does the *pro forma*, requiring such notice only if the outage is anticipated to last for greater than 25 days. In defense of this contract modification, Mystic has repeatedly pointed to the risk that a

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[329] Bentz Testimony, Exh. NES-001 at 15:4-5. NESCOE disagrees with Mr. Schintzer's contention that it is not clear whether more than one capacity commitment period is implicated by the addition of the language: "During any three (3) month period from December – February." The added clause clearly refers to a single and continuous three-month period (i.e., one capacity commitment period at a time). To eliminate any possible confusion, NESCOE clarifies that the language would apply to the three-month winter period in 2022-2023 and then again to the three-month winter period in 2023-2024.

[330] Bentz Testimony, Exh. NES-001 at 15:11-12.

[331] Exh. NES-003 at 3.

replacement cargo of LNG could take weeks to arrive.[332] In fact, ISO-NE confirmed that the change from ten to 25 days was made to address "Exelon's claim that it will take approximately two weeks to receive a shipment of LNG on an emergency basis if a scheduled delivery fails to arrive due to force majeure event."[333] Through this change to the *pro forma*, all other instances in which the resources could have prolonged or catastrophic events are effectively cast aside solely to protect Mystic from this discrete risk that it can manage.

As discussed above, neither party to the Agreement focused on consumer risks in developing the Agreement. Extending the notice trigger by 250%, from ten to 25 days, translates to roughly one-third of the winter period that ISO-NE has identified as a driving factor for needing to retain the Mystic Units and, in turn, needing the Agreement. To illustrate, Mystic could anticipate that the Mystic Units will be non-operational for almost the *entire month* of February 2023 and would not have to notify ISO-NE of the expected prolonged outage, providing little or no lead time for the grid operator to manage fuel security or other reliability challenges resulting from the outage (or, worse, a more serious and sustained outage). The Commission should not countenance the avoidance of a basic notification feature in the *pro forma* agreement. Nor should consumers have to bear risks to reliable service or pay the full cost-of-service rate to Mystic over the long 25-day period if, for example, the resources had a catastrophic operational failure. A ten-day notification trigger, as reflected in the *pro forma*, more appropriately balances risks between the resource owner and the consumers who are paying the bill.

Mr. Schnitzer posits that consumers would not end up seeing a benefit in connection with Mr. Bentz's recommended change because while "Mystic/Constellation LNG is waiting for the

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[332] Schnitzer Supplemental Testimony, Exh. MYS-014 at 14:4-11; 45:22-23 – 46:1-9.

[333] Exh. NES-003 at 7.

spot cargo to arrive, Mystic would still be exposed to $30 million/month in pay-for-performance and other winter penalties pursuant to Section 3.7 of the Mystic Agreement."[334] This misses the mark. The exposure to potential penalties for non-performance or failure to meet contractual obligations has no bearing on whether Mystic should provide more timely notice to ISO-NE regarding a forced outage situation, whether fuel related or not. Indeed, if Mr. Schnitzer is underscoring that consumers rather than Mystic will ultimately foot the bill for a forced outage no matter what the cause, he effectively points out yet another example where no party to the contract was watching the cash register or concerning themselves with consumer interests.

Mystic has not justified its proposed departure from the Notice of Forced Outage requirement in the *pro forma*. The Commission should direct reinstatement of the ten-day notice trigger.[335] In addition, as Mr. Bentz recommended, in light of the identified reliability risks during the winter months, the notice trigger should be reduced to three days during the winter period.[336] At a minimum, should the Commission agree with Mystic's concern about the timing in connection with LNG cargo replacement, it should nonetheless direct the reinstatement of the ten-day trigger while ordering a narrow exemption for replacement cargo to address Mystic's concern.[337]

iii. Planned outages should not be taken during the winter period.

There is a critical mismatch between ISO-NE's identified need for Mystic 8 & 9 during the critical winter period and the absence of any provision in Section 7.1.1[338] prohibiting Mystic

[334] Schnitzer Rebuttal Testimony, Exh., MYS-0053 at 46:7-10.

[335] Exh. NES-002 at 2.

[336] Bentz Testimony, Exh. NES-001 at 21:1-4; Exh. NES-002 at 2.

[337] Schnitzer Rebuttal Testimony, Exh. MYS-0053 at 45:22-23, 46:1-3.

[338] Exh. MYS-0080 at 23.

from taking a planned outage in this winter period. The Commission should correct this mismatch by directing the change to this provision reflected in Attachment A.[339]

Mr. Schnitzer provided a list of reasons why the provision should remain unchanged. First, he cited to "the difficulty of scheduling outages for all of the units and in light of other outages that may be occurring on the transmission system."[340] NESCOE does not quarrel with these possible challenges, but understands that ISO-NE seeks this unusual and costly agreement primarily to protect fuel security during the winter period.[341] To that end, as the planning coordinator, ISO-NE should work to ensure that no planned outage of the Mystic Units is needed during the winter period. Lastly, Mystic fails to explain why Section 7.1.1 cannot be modified in the way NESCOE suggests while accounting for the limited exceptions Mystic provides. Mystic makes no effort to balance its interests with the interests of those funding its assets.

Second, Mr. Schnitzer stated: "As Planned Outages do not excuse the failure to perform under either Pay for Performance or the Winter Fuel Security Penalty, Mystic will be exposed to significant penalties under the Mystic Agreement for the failure to perform, which will act as very strong incentive for Mystic to avoid scheduling Planned Outages in the Winter."[342] That may be true, but an incentive is not a substitute for an obligation to plan outages in the nine other months of the year when ISO-NE has suggested that fuel security risks are not as acute.

Finally, Mr. Schnitzer concluded that "hard-wiring a prohibition on Planned Outages from December 1 to February 28 may result in a waiver having to be sought to accommodate an

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339 Attachment A at 24; Exh. NES-002 at 2

340 Schnitzer Rebuttal Testimony, Exh. MYS-0053 at 45:2-3.

341 *See supra* notes 324-325.

342 Exh. MYS-053 at 45:3-7.

outage that poses little threat to fuel security."[343] This line of defense is puzzling. NESCOE's proposed revisions do not prevent Mystic from taking outages during the winter period; unplanned outages are, of course, always a possibility. Furthermore, Mr. Schnitzer provides no support for his contention that an outage during the winter period will pose "little threat to fuel security." The Commission should give his statement no weight. To the contrary, ISO-NE has identified the loss of the Mystic Units as a fuel security risk and a more acute risk during the winter months,[344] and the Commission should not permit Mystic to take extended planned outages during these months.

c. The Commission Should Require Mystic to Reinstate the "Best Efforts" Standard in Section 7.1.2(e).

Under Section 7.1.2(e) of the Agreement,[345] the Commission may approve ISO-NE's payment of additional expenses to the Lead Market Participant (*i.e.*, ExGen) in connection with the recovery from a Forced Outage or provision of substitute service. The Agreement modified the *pro forma* language by swapping ExGen's responsibility to "use its best effort to minimize" these additional expenses with a "commercially reasonable" standard. Mr. Bentz recommended that the *pro forma* standard, which protects consumers, be reinstated because Mystic provided no justification for its preference for a lower standard.[346]

Mr. Schnitzer attempted to defend the proposed change in his rebuttal testimony:

> [M]y understanding is that the "commercially reasonable" standard was negotiated for in this instance because the "best" efforts standard could require Mystic to spend money out of its own pocket to minimize Additional Expenses, which defeats the purpose of the provision altogether. The Option to Approve

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343 *Id*. at 45:7-9.

344 *See supra* notes 324-325.

345 Exh. MYS-0080 at 24.

346 Bentz Testimony, Exh. NES-001 at 21:10-18.

> Additional Expenses reflected in Section 7.1.2. is designed to allow resources like Mystic [*sic*] receive payment for unexpected expenses that result from a Forced Outage. Setting a standard that could be interpreted to require Mystic to spend money that would not subsequently be recovered to minimize the cost of needed repairs is not consistent with the purpose of this section of the Agreement – which is to allow the resource to cover its costs.[[347]]

NESCOE does not agree with Mr. Schnitzer's characterization of Section 7.1.2(e). The provision sets forth a *process* for payment of Additional Expenses, not an entitlement for ExGen to cover its costs. That process requires Commission approval and it obligates ExGen to minimize the expenses incurred. Changing the standard applied to ExGen's efforts to minimize these additional expenses, which may be borne by consumers, is a material change.

NESCOE also disagrees with Mr. Schnitzer's contention that a "best efforts" standard might "require Mystic to spend money out of its own pocket to minimize Additional Expenses."[348] As NESCOE understands the provision, it requires ExGen to *avoid* spending money. Mr. Bentz provided an example during the hearing to illustrate why the "best efforts" standard is important:

> I want to make sure that the preparing folks, the operations folks, the maintenance folks are trying their hardest to minimize expenses as opposed to just saying yeah, bring in [General Electric] at their full rates to do the work.[[349]]

Mystic has not provided a reasonable justification for departing from the *pro forma* standard set forth in Section 7.1.2(e). The "best efforts" standard should be reinstated, as reflected in Attachment A.[350]

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[347] Schnitzer Rebuttal Testimony, Exh. MYS-0053 at 46:13-21.

[348] *Id.* at 46:14-15.

[349] Tr. 1647:18-22.

[350] Attachment A at 26; Exh. NES-002 at 2-3.

d. The Commission Should Require a Section 205 Filing to Modify the FSA.

Mr. Bentz recommended two changes to Section 3.9 of the Agreement, which as drafted requires Mystic to provide ISO-NE with copy of proposed material modifications of the FSA and to make an informational filing with the Commission.[351] First, Mr. Bentz proposed that the filing with the Commission be made pursuant to FPA section 205, 16 U.S.C. 824d.[352] As Mr. Bentz explained: "The FSA is intricately tied to the costs that Mystic seeks to recover under the Agreement. An informational filing is insufficient protection against material modifications that could fundamentally alter the FSA and expose consumers to greater risk and/or cost."[353]

Second, Section 3.9 does not appear to require any Commission filing if Mystic proposes to modify "the conceptual method for calculating any margin earned on any third-party sales of LNG re-gasified through" EMT. It requires only ISO-NE's consent. While ISO-NE appears to interpret this provision as requiring a Commission filing for this modification,[354] the contract language is unclear. Mr. Bentz recommended that Section 3.9 be revised to require Mystic to make an informational filing before modifying the conceptual method for calculating any margin on these third-party sales.[355] Mr. Bentz explained why this change is necessary: "The model used to calculate the margin on these sales is critical to the apportionment of risks to Mystic on the one hand and consumers on the other. The sale of re-gasified LNG to third-parties materially affects the Monthly Fuel Supply Cost under the structure Mystic has proposed."[356]

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[351] Exh. MYS-0080 at 18.

[352] Bentz Testimony, Exh. NES-001 at 17:10-11; Exh. NES-002 at 1.

[353] Exh. NES-001 at 17:8-10.

[354] Exh. NES-003 at 6.

[355] Exh. NES-001 at 17:12-22.

[356] *Id.* at 17:15-18.

The Commission should direct the revisions to this provision that are reflected in Attachment A.[357]

2. Mystic's Recovery of Property Taxes Related to Mystic 7 Is Unjust and Unreasonable.

Mystic has included $15.5 million in costs to recover through the Agreement related to "Other Taxes."[358] Of this amount, **[BEGIN CUI/PRIV-HC]** [redacted] **[END CUI/PRIV-HC]**.[359] The Commission should reject Mystic's attempt to shift its property tax burden related to the Mystic 7 site ("Mystic 7") to consumers as part of its cost-of-service arrangement for Mystic 8 & 9.

Mystic makes no attempt to explain why consumers bearing costs related to Mystic 8 & 9 must pay property taxes related to an entirely separate parcel of land. Its sole rationale is a tortured syllogism: (1) Mystic has decided to retire Mystic 7 and the jet units, (2) after that retirement there will be outstanding property taxes for the Mystic 7 site, and (3) consumers rather than Mystic shareholders should pay those taxes.[360] A driver isn't relieved of paying excise taxes simply because she stops driving her car. Nor can she shift her tax burden to a neighbor driving a different car.

Mystic's attempt to shift its tax liability for Mystic 7 is particularly egregious in light of its ability to sell the Mystic 7 land and any equipment and use those profits to meet its property tax obligations. Mr. Bentz noted that the sale of Mystic 7 "would provide Mystic with an influx

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357 Attachment A at 19.

358 Exh. MYS-0050 at 1 (Schedule A, line 18).

359 Exh. NES-005 at 2 (line 42); Exh. NES-047 at 1.

360 Heintz Rebuttal Testimony, Exh. MYS-0037, at 23:21-23 – 24:1 (". . . the Mystic 7 and jet units are to be retired before the term of Mystic Agreement, and when that occurs, all the property taxes for the Mystic units will be allocated to the only remaining units, Mystic 8 & 9.").

of cash, which it can apply toward the share of Mystic 7 property taxes."[361] Mr. Heintz disputed that "the salvage value for those units can offset the property tax expenses associated with the Mystic Agreement" and characterized Mr. Bentz's claim as "speculative and without foundation."[362] But it is *Mystic's burden* to establish that its recovery of property taxes from consumers is just and reasonable, and it has offered only the *timing* of the Agreement as the basis for recovery.[363] Notably, Mystic has not rebutted Mr. Bentz's assertion that Mystic can and should use any proceeds from the sale of Mystic 7 site to pay property taxes related to that same site. In fact, Mr. Schnitzer **[BEGIN CUI/PRIV-HC]** [redacted] **[END CUI/PRIV-HC]**[364]

Contrary to Mr. Heintz's assertion, Mr. Bentz does not propose the allocation of property taxes to "units that no longer exist"[365] but rather to Mystic's shareholders. That is the result of allocating "the property taxes during the [cost-of-service period] to Mystic 7, 8, and 9 in the same way [Mystic] did before that period,"[366] and it is the only just and reasonable outcome based on the record in this proceeding. In contrast, under the Mystic proposal, shareholders would receive the financial benefit of the sale of the site while shifting the corresponding costs to consumers, providing the company with windfall profits at consumers' expense. In fact, as Mystic has confirmed, if Mystic 8 & 9 were to retire on May 31, 2022, along with Mystic 7 and

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[361] Bentz Testimony, Exh. NES-001 at 28:20-21.

[362] Heintz Rebuttal Testimony, Exh. MYS-0037at 24:4-7.

[363] *Id*. at 23:20-22.

[364] Schnitzer Rebuttal Testimony, Exh. MYS-0053 43:4-5.

[365] Heintz Rebuttal Testimony, Exh. MYS-0037 at 24:3-4.

[366] Bentz Testimony, Exh. NES-001 at 28:17-18.

the jet, Mystic would still be assessed the property taxes for the periods after the retirements.[367] In that case, **[BEGIN CUI/PRIV-HC]** [redacted] **[END CUI/PRIV-HC]**[368]

The Commission should reject Mystic's attempt to pass property taxes for Mystic 7 to consumers who are being asked to fund Mystic 8 & 9 for fuel security purposes. Nor should it allow Mystic to defer the issue to the Schedule 3A true-up and challenge process, as Mystic suggests.[369] These property tax charges are "unnecessarily incurred" in relation to Mystic 8 & 9 and should be disallowed now.[370] Instead, the Commission should set clear guidelines for the recovery of property taxes, requiring that they be allocated at the same percentage as they were prior to the cost-of-service period.[371]

3. Mystic's Recovery of Costs Related to Moving the Auxiliary Boiler Is Unjust and Unreasonable.

Mystic seeks to recover $12 million in capital expenditures to "Move/Replace the Auxiliary steam boiler" from Mystic 7 and relocate it on the Mystic 8 & 9 site.[372] Mystic states that "continued operation of [the Mystic Units] beyond May 2022 requires this relocation given the sale of the" Mystic 7 property.[373] Mystic 7 will be retired before the start of the cost-of-

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367 Exh. NES-039 at 5.

368 Tr. 679:7-11.

369 Heintz Rebuttal Testimony, Exh. MYS-0037 at 24:1-3.

370 *Mountain States Tel. & Tel. Co. v. F.C.C.*, 939 F.2d 1035, 1043 (D.C. Cir. 1991) (citing *NAACP v. FPC*, 425 U.S. 662, 666, 668 (1976) (Federal Power Act requires the disallowance of rates based on illegal or unnecessary charges)).

371 Bentz Testimony, Exh. NES-001 at 29:3-7. As stated in the Bentz Testimony, Mystic has confirmed that this allocation is **[BEGIN CUI/PRIV-HC]** [redacted] **[END CUI/PRIV-HC]**. Exh. NES-006.

372 Exh. MYS-005 at 5.

373 *Id*.

service period (*i.e.*, June 1, 2022).[374] Mr. Schnitzer explained that the Mystic 7 auxiliary boiler "is currently used to provide start up steam for Mystic 8 or 9 when Mystic 7 is not on line. If Mystic 8/9 were to retire at the end of May 2022, there would be no need to relocate or replace the auxiliary boiler."[375] Mr. Schnitzer further described the status of the Mystic 7 site:

[BEGIN CUI/PRIV-HC]

> [redacted][376]]

[END CUI/PRIV-HC].

The Commission should disallow Mystic's recovery of costs associated with relocating the auxiliary boiler. Mystic postures that the relocation of the boiler is for the benefit of Mystic 8 & 9. **[BEGIN CUI/PRIV-HC]** [redacted]

[374] Heintz Rebuttal Testimony, Exh. MYS-0037 at 23:21-22.

[375] Schnitzer Rebuttal Testimony, Exh. MYS-0053 at 42:18-20.

[376] *Id.* at 43:4-12. Mr. Schnitzer confirmed during the hearing that **[BEGIN CUI/PRIV-HC]** [redacted] **[END CUI/PRIV-HC]** Tr. 879:14-17.

[377] Schnitzer Rebuttal Testimony, Exh. MYS-0053 at 43:7-12.

[redacted]

[END CUI/PRIV-HC]

Mystic has made no attempt to justify why consumers should be forced to bear the boiler relocation costs just because Mystic is in the **[BEGIN CUI/PRIV-HC]** [redacted] **[END CUI/PRIV-HC]**

Moreover, Mystic, as with the property tax issue discussed above, would be unjustly enriched by reaping the financial rewards of selling Mystic 7 and passing the costs related to the

378 Tr. 887:8-14.

379 Tr. 879:14-17.

sale to consumers. The timing of the auxiliary boiler relocation is, by Mystic's admission, directly correlated with its sale of the property.[380] Just because the **[BEGIN CUI/PRIV-HC]** [redacted] **[END CUI/PRIV-HC]** When a house is sold, it is the seller's responsibility to move equipment that the new owner does not want. The seller can try to negotiate with the buyer for the disposal of that equipment, but if no deal is reached the seller cannot elect instead to pass the costs onto a third-party. Any costs to Mystic related to moving the auxiliary boiler off of the Mystic 7 property to complete a sale are Mystic's alone to bear, just as any profits from a sale are Mystic's to keep.

Further, the Commission should disallow cost recovery until Mystic has corrected gaps in its analysis. First, Mystic never considered whether it should seek an Agreement involving Mystic 7 & 8 instead of Mystic 8 & 9, which would have obviated the need to move the boiler.[381] It failed to consider how the costs to consumers would have compared[382]—and whether they would have been reduced—under that arrangement as opposed to the one currently before the Commission.[383] Without this analysis, Mystic cannot demonstrate that its proposal to relocate the boiler is the least-cost option.

Second, Mystic makes much of the asserted "cost inefficiencies" of keeping the boiler at Mystic 7 because the employees at that site operate under a different collective bargaining

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380 Exh. MYS-005 at 5 ("continued operation of [the Mystic Units] beyond May 2022 requires this relocation given the sale of the" Mystic 7 property). *See also* Exh. NES-045 at 2 ("The boiler cannot remain in its current location because it is located on a parcel of land that Mystic anticipates selling to a third party.").

381 Tr. 691:10-22 (Berg).

382 *See* Tr. 886:2 – 887:10 (Schnitzer).

383 Tr. 691:10-22 (Berg).

agreement.[384] But, again, Mystic never considered whether keeping the boiler in-place with Mystic 7 employees was the least-cost option, let alone performed any analysis of those costs.[385]

At minimum, the Commission must require Mystic to explain in greater detail why it should be entitled to recover $12 million in costs related to the boiler move. Mr. Bentz described the report that Mystic relied upon to justify the costs associated with the auxiliary boiler relocation:

> Mystic . . . provides . . . a copy of a report **[BEGIN CUI/PRIV-HC]** [redacted] **[END CUI/PRIV-HC]**.[[386]]

As Mr. Bentz stated, Mystic has never explained "why it is seeking *$12 million* for the project."[387] Mystic has the burden of justifying these costs. Moreover, the **[BEGIN CUI/PRIV-HC]** [redacted] **[END CUI/PRIV-HC]** than the proposed $12 million that Mystic seeks to recover.[388] The cost-of-service period is two-years. As Mr. Bentz noted, **[BEGIN CUI/PRIV-HC]** [redacted]89 **[END CUI/PRIV-HC]** Absent a more complete explanation for the $12 million cost, the Commission should only allow Mystic **[BEGIN CUI/PRIV-HC]** [redacted]

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384 Schnitzer Rebuttal Testimony, Exh. MYS-0053 at 43:14-19.

385 Exh. NES-046 at 10 (NES-MYS-16-42).

386 Bentz Testimony, Exh. NES-001 at 33:1-9.

387 *Id.* at 33:10 (emphasis supplied).

388 Exh. NES-008 at 8-9.

389 Bentz Testimony, Exh. NES-001 at 34:7-8.

[redacted] **[END CUI/PRIV-HC]** if it seeks to incur those higher costs in the interest of a better financial outcome for its shareholders. Those additional costs just should not be passed on to ratepayers.

Like Mystic's proposed cost recovery of property taxes, Mystic seeks to punt the recovery of expenses related to the auxiliary boiler to the proposed Schedule 3A process. That process, however, does not allow Mystic to recover costs that are disallowed as a matter of law.[390] The Commission should set a clear standard now regarding cost recovery for the auxiliary boiler.

4. Mystic Should Not Be Permitted To Recover Its Claimed Costs Related to the Supposed "Expected Change" to Medium Impact Status.

Mystic witness Berg sponsors Exhibit MYS-005, which lists the "Capital Costs of Mystic 8&9 and Everett."[391] That exhibit includes an expenditure for Mystic 8 & 9 in 2022 of $8,752,629 in connection with "NERC-CIP Incremental Capex"—*i.e.*, capital expenditures related to compliance with North American Electric Reliability Corporation ("NERC") critical infrastructure protection ("CIP") requirements.[392] Mystic attributed to this expenditure to "the expected change to medium impact facility designation."[393] Mystic also includes, in Exhibit MYS-0050 **[BEGIN CUI/PRIV-HC]** [redacted]

[390] *Mountain States*, 939 F.2d at 1043; *NAACP*, 425 U.S. at 666, 668 (Federal Power Act requires the disallowance of rates based on illegal or unnecessary charges).

[391] Exh. MYS-001 at 5:9.

[392] Exh. MYS-005 at 5.

[393] *Id.*

[redacted][394] **[END CUI/PRIV-HC]** In his testimony, Mr. Berg explains that when "ISO-NE, as planning coordinator for the Mystic units, has designated Mystic 8&9 as resources needed to ensure reliability for the ISO-NE region for a period longer than one year, their classification under NERC Reliability Standard CIP-002-5.1a Requirement R1.1 will automatically change from 'low impact' to 'medium impact' BES Cyber Systems," and they will be "subject to all of the key cybersecurity controls mandated by the CIP Reliability Standards."[395] However, the record does not support Mr. Berg's conclusion that ISO-NE will take the necessary action to cause Mystic 8 & 9 to be reclassified as medium impact facilities. Mystic has not demonstrated that its expenditures in connection with the CIP requirements are just and reasonable, and the Commission should disallow them.

Reliability Standard CIP-002-5.1a Requirement R1 requires each Responsible Entity to identify each of its high impact, medium impact, and low impact cyber assets.[396] Attachment 1 to that Standard, "Impact Rating Criteria," explains that medium impact facilities include "Each generation facility that its Planning Coordinator or Transmission Planner designates, and informs the Generator Owner or Generator Operator, as necessary to avoid an Adverse Reliability Impact in the planning horizon of more than one year."[397]

Impact Rating Criterion 2.3 confirms that, for a generation facility to be classified as medium impact, ISO-NE, in its role as the planning coordinator for the New England region, must do two things. First, the planning coordinator must designate a generation facility as necessary to avoid an Adverse Reliability Impact in the planning horizon of more than one year.

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[394] Exh. MYS-0050 at 6.

[395] Berg Direct Testimony, Exh. MYS-0001 at 21:14-19.

[396] https://www.nerc.com/pa/Stand/Reliability%20Standards/CIP-002-5.1a.pdf, at 2.

[397] *Id*. at 15.

Second, the planning coordinator must inform the Generator Owner or Generator Operator that it has so designated the generation facility.

At the hearing, Mystic witness Heintz claimed that ISO-NE has already notified Mystic that Mystic 8 & 9 are necessary to avoid an Adverse Reliability Impact in the future, although he could not say when the notification took place, or whether the notification was communicated verbally or in writing.[398] Mr. Heintz's response, however, is twice contradicted. First, as discussed above, Mr. Berg's testified that Mystic 8 & 9 will become medium impact assets *at some point in the future*, "Once ISO-NE … has designated Mystic 8&9 as resources needed to ensure reliability…"[399]

Second, contrary to Mr. Heintz's unsupported claim, ISO-NE has neither designated Mystic 8 & 9 as necessary to avoid an Adverse Reliability Impact in the planning horizon of more than one year nor informed Mystic of any such designation. And contrary to Mr. Berg's testimony, the record indicates that future action by ISO-NE to so designate Mystic 8 & 9 is neither inevitable nor even likely.

ISO-NE has stated explicitly that "ISO-NE has not determined that continued operation of Mystic 8 and/or Mystic 9 are necessary to avoid an 'Adverse Reliability Impact' as that term is defined in the NERC Glossary of Terms."[400] In response to a later data request, ISO-NE repeated that it "does not have a position on, whether operation of Mystic 8 and 9 during the Cost-of-Service Agreement period is necessary to avoid an Adverse Reliability Impact."[401] These statements by ISO-NE, the planning coordinator, directly refute Mr. Heintz's testimony

[398] Tr. 323:23-324:8.

[399] Exh. MYS-001 at 21:14-15.

[400] Exh. NES-051 at 15.

[401] *Id.* at 18.

that ISO-NE has designated Mystic 8 & 9 as necessary to avoid an Adverse Reliability Impact and has so informed Mystic. Finally, in response to NESCOE Data Request NES-ISO-3-4, ISO-NE stated that it "does not utilize the definition of Adverse Reliability Impact in its transmission planning studies or other studies related to reliability."[402] These responses make clear that: (i) ISO-NE, the planning coordinator : has *not* designated Mystic 8 & 9 as necessary to avoid an Adverse Reliability Impact, and (ii) it is doubtful that ISO-NE will designate Mystic 8 & 9 as necessary to avoid an Adverse Reliability Impact at any time in the future. Without such a designation, Mystic 8 & 9 would not be classified as medium impact facilities.

In addition, ISO-NE has confirmed that it has not identified Mystic 8 or 9 as "critical" pursuant to other aspects of the CIP requirements.[403] ISO-NE stated that:

> Regarding the criteria set forth in CIP-002-5.1a, Attachment 1, 2.6, given ISO-NE's current understanding of the system, existing and planned, ISO-NE does not anticipate any changes and anticipates that it will continue not to identify Mystic 8 or Mystic 9 as "critical" under the CIP requirements, particularly CIP-002-5.1a, Attachment 1, 2.6 relating to the Medium Impact Rating (M) criterion. ISO-NE will continue to evaluate any potential changes to the CIP-002-5.1a determinations for Mystic 8 and 9 as new information becomes available."[404]

Thus, like ISO-NE's view of CIP-002-5.1a Requirement R1, it confirms that other aspects of the CIP requirements similarly do not require ISO-NE to designate the Mystic Units as medium impact facilities, and that ISO-NE has no plans to do so in the future.

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[402] *Id.* at 16.

[403] Exh. NES-051 at 9.

[404] *Id.* at 9.

To be clear, NESCOE is not proposing that Mystic should be denied recovery of justified costs incurred to comply with FERC-approved mandatory reliability standards.[405] Rather, Mystic's claim that Mystic 8 & 9 will meet the criteria to be classified as medium impact units or that this classification is solely related to the cost-of-service period is unsubstantiated. ISO-NE has not designated those units as necessary to avoid an Adverse Reliability Impact in the long-term planning horizon, and the record makes it unlikely that ISO-NE will so designate the units in the future. Unless and until ISO-NE does make such a designation, determines that such designation is solely due to the need for the Agreement, and communicates that designation to Mystic, Mystic 8 & 9 do not qualify as medium impact units. Mystic will, therefore, not be required to undertake the expenditures necessary to comply with requirements applicable to medium impact units. Should Mystic decide to undertake such expenditures anyway, it is appropriate for such optional expenditures to be borne by the shareholders.

FINDINGS OF FACT AND CONCLUSIONS OF LAW

(Note: The issues as articulated in the "Proposed Joint Statement of Issues," submitted by the parties on September 19, 2018, are replicated below to aid the Commission in tracking the issues along with NESCOE's findings of fact and conclusions of law.)

I. Whether the rate proposed to be collected under the Mystic Cost-of-Service Agreement ("Mystic Agreement") is just and reasonable?

A. Whether the proposed calculation of non-fuel costs is just and reasonable?

i. Whether the proposed annual fixed revenue requirement ("AFRR") for Mystic 8 & 9 is just and reasonable?

1. Whether the proposed rate base for Mystic 8 & 9 is just and reasonable?

[405] If the Commission does allow cost recovery related to the CIP designation, Mystic should be required to support its expenditures, which are estimated down to the penny, with greater specificity. The record lacks any evidentiary support.

a. Are the proposed gross and net plant values used in the proposed AFRR just and reasonable?

1. Mystic has not demonstrated that the rate to be collected under the Agreement is just and reasonable.

2. The proposed AFRR for Mystic 8 & 9 is not just and reasonable.

3. The proposed rate base for Mystic 8 & 9 is not just and reasonable because Mystic has failed to take into consideration any impairments on those assets, and therefore, Mystic has failed to value the Mystic Units based on conditions as they exist today.

4. Impairment exists when the expected future nominal (undiscounted) cash flows, excluding carrying charges, are less than the carrying amount.

5. **[BEGIN CUI/PRIV-HC]** [redacted] **[END CUI/PRIV-HC]**

6. An impairment assessment of Everett shows **[BEGIN CUI/PRIV-HC]** [redacted] **[END CUI/PRIV-HC]**

7. ISO-NE has, to date, not proposed market rule changes to implement a long-term solution to fuel security—contradicting an assumption that was made in Exelon's asset group impairment analysis.

8. Because Mystic is seeking approval for a cost-of-service agreement solely for the Mystic Units, a stand-alone impairment assessment for just those asserts is necessary to develop an accurate value for those units.

9. Whether or not the wholesale markets were "working" in the past is irrelevant to a proper current valuation of the Mystic Units.

10. Mystic seeks to recover not only expenses it would incur but for a decision to continue operating but significant additional costs including $136 million in return on equity and $72 million in depreciation expense. There are several significant costs for which Mystic seeks recovery that it would incur even if it were to retire, including **[BEGIN CUI/PRIV-HC]** [redacted] **[END CUI/PRIV-HC]**

11. Mystic's threats to retire cannot supplant the Commission's obligation to ensure that the rates under the Agreement are just and reasonable.

b. Is the proposed accumulated depreciation just and reasonable?

12. The amount of accumulated depreciation reserves that Mystic subtracts from its gross plant is understated by over $200 million.

c. Whether there should be a reduction in rate base for regulatory liability to reflect excess deferred income taxes ("EDIT").

13. Mystic has conceded that there should be a reduction in the tax allowance for the EDIT amortization, grossed-up for taxes in the amount of $2,038,678.

d. Is the proposed cash working capital (CWC) just and reasonable?

14. Mystic has not justified using one-eighth of its O&M expenses as CWC in this case, given that Mystic's request to expense all capital expenditures for Mystic 8 & 9 during the cost-of-service period greatly enhances Mystic's cash flow during this period.

15. In the absence of a lead/lag study—and there is no justification for Exelon's lacking one—the CWC for Mystic should be set at zero.

16. Mystic's proposed use of the one-eighth method overstates rate base by approximately $2.4 million.

2. Whether the proposed weighted average cost of capital for Mystic 8 & 9 is just and reasonable?

a. Whether the proposed return on equity is just and reasonable?

i. Is the proposed proxy group just and reasonable?

ii. Are the growth rates used to calculate the implied cost of equity for the proposed AFRR appropriately calculated?

iii. Is the proposed placement of Mystic's return on equity within the range of DCF results just and reasonable?

17. Mystic has not demonstrated that its proposed return on equity is just and reasonable. Record evidence submitted by the Connecticut Parties, Staff and ENECOS demonstrates that the ROE should be lower than what Mystic requests.

b. Whether the proposed capital structure is just and reasonable?

18. Mystic's request for an ROE based on a capital structure of 32.7% debt and 67.3% equity is unjust and unreasonable in light of Exelon's capital structure consisting of approximately 52.38% debt and 47.62% equity as of June 2018.

19. The Commission should either use a double leverage capital structure approach or set Mystic's capital structure to 52.4% debt and 47.6% equity.

c. ***Whether the proposed cost of debt is just and reasonable?***

20. [NESCOE does not address this issue in its brief.]

B. Whether the proposed fuel costs are just and reasonable?

i. Whether the proposed Fixed O&M/Return on Investment component of the Monthly Fuel Supply Cost is just and reasonable?

1. Is the proposed rate base for Everett just and reasonable?

a. Are the proposed gross and net plant values used for Everett just and reasonable?

21. Mystic has not demonstrated that the proposed gross and net plant values for Everett are just and reasonable.

22. Mystic's affiliate, ExGen, purchased the Everett facility from Engie (DOMAC) for **[BEGIN CUI/PRIV-HC]** [redacted] **[END CUI/PRIV-HC]**

23. The record evidence supports a net plant value for Everett at or near zero dollars.

24. **[BEGIN CUI/PRIV-HC]** [redacted] **[END CUI/PRIV-HC]**

25. **[BEGIN CUI/PRIV-HC]** The Balance Sheet for DOMAC provided in Schedule 2.11 of the MIPA reflects an impairment adjustment in the amount of $249,841,000 in 2017. **[END CUI/PRIV-HC]**

26. **[BEGIN CUI/PRIV-HC]** [redacted] **[END CUI/PRIV-HC]**

27. Impairment of an asset or asset group exists when the expected future nominal (undiscounted) cash flows, excluding interest charges, are less than the carrying amount.

28. A fair value write down occurs when it is determined that an asset has been impaired because its fair value is below its recorded cost.

29. **[BEGIN CUI/PRIV-HC]** [redacted] **[END CUI/PRIV-HC]**

30. For rate regulated utilities, plant impairment is, in fact, a form of depreciation recognized by FERC's Uniform System of Accounts.

31. To the extent that Everett is subject to GAAP rules, the rate base value should be zero. Using the **[BEGIN CUI/PRIV-HC]** [redacted] **[END CUI/PRIV-HC]** as the rate base violates the GAAP rule that restoration of a previously recognized impairment loss is prohibited.

32. **[BEGIN CUI/PRIV-HC]** [redacted] **[END CUI/PRIV-HC]**

33. **[BEGIN CUI/PRIV-HC]** [redacted] **[END CUI/PRIV-HC]**

34. Under FERC's USoA rules, applicable to Mystic which is now seeking cost-of-service treatment, when a utility acquires property, the value of the property that is recorded in plant in service on the books of the utility is recorded at original cost less depreciation, including impairment. Any amounts paid in excess should be recorded as an acquisition premium.

35. Mystic has not met the criteria specified in the Commission's two-prong "substantial benefits" test in *Seaway Crude Pipeline Co., LLC*, 154 FERC ¶ 61,070 at P 92 (2016) to **[BEGIN CUI/PRIV-HC]** [redacted] **[END CUI/PRIV-HC]**

    a. Mystic has not demonstrated that EMT will be converted from one public use to a different public use. Rather, EMT will continue to operate in its present use to provide LNG fuel to Mystic 8 & 9 and to other customers.

    b. Mystic has not shown clear and convincing evidence that its acquisition of the facilities will provide substantial, quantifiable benefits to ratepayers even if the full purchase price, including the portion above depreciated original cost, is included in rate base. Mystic has conducted no such analysis.

    c. Mystic has not shown that the transaction at issue is an arm's length sale between unaffiliated parties. Rather, **[BEGIN CUI/PRIV-HC]** [redacted] **[END CUI/PRIV-HC]**

    d. Mystic has not shown that the purchase price of the asset at issue is less than the cost of constructing a comparable facility.

36. Everett's cash flows over the next ten years are **[BEGIN CUI/PRIV-HC]** [redacted] **[END CUI/PRIV-HC]**

b. Is the proposed accumulated depreciation just and reasonable?

37. The proposed accumulated depreciation is not just and reasonable because it fails to account for **[BEGIN CUI/PRIV-HC]** [redacted] **[END CUI/PRIV-HC]**

c. Is the proposed cash working capital (CWC) just and reasonable?

38. Mystic has not supported the use of one-eighth of annual O&M expenses as a default value for CWC for Everett for the same reasons discussed above with respect to Mystic (*see* items 14-16 above), and the EMT rate base is overstated by approximately $2.3 million.

39. There is no justification for the additional amount that Mystic originally proposed to add for "fuel lag." Mystic has conceded that there is no significant fuel lag and the Commission should remove the additional $4 million set aside for fuel lag from EMT's rate base.

2. Whether the proposed rate of return on equity for Everett is just and reasonable?

40. Mystic has not shown the proposed rate of return on equity to be just and reasonable. Record evidence submitted by the Connecticut Parties, Staff and ENECOS demonstrates that the ROE should be lower than what Mystic requests.

a. Should Everett's return on equity have a different placement than Mystic within the range of DCF results?

41. [NESCOE does not address this issue in its brief.]

ii. Whether the proposal to include all costs of Everett as Mystic fuel costs, less an appropriate credit for third party sales of LNG, is just and reasonable; and what constitutes an appropriate revenue credit?

42. Mystic's proposal to allocate one hundred percent of Everett's fixed costs to Mystic with a 50% credit for third-party sales of LNG is unjust and unreasonable, and would give Constellation LNG insufficient incentives to manage Everett efficiently, resulting in excessive costs passed through to customers and harm to the regional wholesale markets.

43. Mystic should recover no more than 39.16% of Everett's fixed costs; this is proportionate to the facility's actual capability of serving Mystic and takes into consideration Constellation LNG's opportunity recover some of Everett's costs from customers other than Mystic.

44. Recovery of the full fixed costs of Everett by Mystic is anticompetitive, unjust and unreasonable. *See Gulf States Utils. Co. v. FPC*, 411 U.S. 747, 760 (1973).

45. A just and reasonable approach would be the approach recommended by NESCOE witness Mr. Wilson, which would include:

    a. A **Demand Charge**, which would generally reflect Everett's fixed costs, but which would be equal to the maximum capacity that Mystic can receive from Everett on a daily basis, as a fraction of its certificated capacity.

    b. A **Commodity Charge** for actual volumes taken.

c. An **Annual Reliability Charge** to compensate Constellation LNG for additional costs and risks associated with providing firm and flexible service to Mystic. Such charge would provide a payment based on an *ex ante* estimate of costs, and would be set using a probabilistic simulation to model Everett's operations to provide service to Mystic.

46. If the Commission does not adopt the approach recommended by NESCOE witness Mr. Wilson, the 50% margin sharing is unjust and unreasonable and would result in a windfall to Constellation that benefits Exelon.

47. The 50% margin sharing proposal has no evidentiary support in the record.

48. Reducing the share of margin that would accrue to Constellation LNG from 50% to 25% would balance competing interests and reduce risk to consumers.

1. Whether the Fuel Supply Agreement, winter penalties and planning to procure gas for the coldest winter in 50 years create incentives to over-schedule LNG and artificially depress natural gas prices.

49. [NESCOE's brief does not address this issue.]

2. Whether the Fuel Supply Agreement will create an improper subsidy by ratepayers of third-party natural gas sales.

50. [NESCOE's brief does not separately address this issue; rather, it is subsumed in its discussion of the Fuel Supply Agreement, above.]

3. Whether the costs of owning and operating the Everett Marine Terminal should be allocated between those incurred to serve Mystic, on the one hand, and those incurred for third party sales, on the other hand, for purposes of determining cost recovery under the proposed Mystic Cost of Service Agreement.

51. *See* items 42-48 above for NESCOE's position on how the costs of owning and operating Everett should be allocated.

4. Whether (i) the proposed percentage of profit to which Constellation LNG and Mystic would be entitled with respect to third-party sales of gas has been justified and (ii) the calculation of any profit sharing incentive for third party sales of gas should be performed ex post rather than ex ante?

52. As discussed above in item 48, NESCOE believes that if the Commission does not adopt the approach proffered by Mr. Wilson, Constellation LNG should be entitled to 25% of the margins on third-party sales.

5. Whether ISO-NE should be required to engage a third-party expert to assess the prudency of Mystic's and Constellation's gas

procurement and management decisions and, following such assessments, file any disallowances with the Commission under Section 205?

53. *See* items 72-73 below for NESCOE's position on the proposed level of oversight over Mystic and Everett.

iii. Whether the remaining components of the Monthly Fuel Supply Cost are just and reasonable?

54. To ensure the Agreement is just and reasonable, it should be modified so that Mystic energy should be offered in two blocks, with two Stipulated Variable Costs, and resulting offer prices. There is evidence in the record suggesting that Mystic does not oppose this approach.

55. Section 4.4.3 of the Agreement should be modified to account for the opportunity cost adder, otherwise Mystic would receive a windfall each time the adder is deployed.

iv. Whether the remaining terms and conditions of the Amended and Restated Fuel Supply Agreement (FSA) result in rates under the Mystic Agreement that are just and reasonable?

1. Whether the FSA results in just and reasonable fuel charges for Mystic 8 & 9?

56. The FSA does not result in just and reasonable fuel charges for Mystic 8 & 9. Mystic's proposal is fundamentally flawed and should instead reflect an approach that involves (1) a demand charge, under which Mystic would be responsible for 39.16% of Everett fixed cost; (2) a commodity charge for actual volumes taken, based on world LNG price index; and (3) a reliability charge to cover additional risks related to providing firm, reliable and flexible fuel supply.

C. Whether the proposed Schedule 3A is just and reasonable, and satisfies the Commission's directive to develop a true-up?

i. Whether the proposed true up information exchange process and challenge protocols are just and reasonable?

57. Mystic's failure to require informational filings detailing the capital expenditures made over the preceding calendar year shows a lack of transparency and makes it more difficult to meaningfully review and challenge such costs.

58. Certain costs should be disallowed, even in the true-up. These include:

   a. CWC;

   b. Overtime labor expenses in excess of 21% of base pay;

c. Incentive pay based on financial performance, and incentive pay in excess of 13.3%; and

d. O&M expenses that exceed a 2% cap.

59. Contrary to the Hearing Order, Mystic proposes to place artificial restrictions on the true-up process. All components of rate base for which Mystic seeks cost recovery should be subject to the true-up process.

60. Mystic's proposed true-up procedures that would limit information exchange to "what *is necessary* to determine" various items and criteria related to the true-up filing is overly restrictive and inconsistent with the recent formula rate protocols pending before the Commission in Docket Nos. ER18-2235-000, *et al.*

61. Mystic's challenge procedures include unreasonable restrictions on the filing of formal challenges.

62. Mystic's challenge procedures include redundant language that is confusing and should be removed.

63. Mystic's challenge procedures do not provide sufficient time for interested parties to submit a formal challenge; an additional month is needed.

D. Whether a clawback provision should be adopted, and, if so, what amounts should be refunded and under what circumstances/conditions?

64. Clawback mechanisms address the possibility that a cost-of-service resource will reenter the competitive wholesale markets after a cost-of-service period has concluded.

65. Without a clawback provision, the Agreement is not just and reasonable and is inconsistent with the Commission's precedent requiring clawback provisions in other situations involving reliability-must-run generators. *See N.Y. Indep. Sys. Operator, Inc.* 161 FERC ¶ 61,189, at P 83 (2017).

66. A clawback provision is needed in this case to prevent an inequitable and inappropriate outcome for consumers and to prevent the Mystic Units from having an unfair competitive advantage.

67. A clawback provision should also address the Commission's concern of discouraging an otherwise efficient generator from continuing to operate to the detriment of customers.

68. A just and reasonable and balanced clawback provision would apply to Mystic 8 & 9—triggered when their interconnection rights are terminated—and to EMT—triggered when EMT has not vaporized gas for a continuous three-month period.

69. A just and reasonable and balanced clawback mechanism would be based on capital expenditures made during the cost-of-service period and costs for repairs that provide

significant benefits beyond the end of that period, with such amounts to be refunded over a four-year straight-line period.

70. It would be unjust and unreasonable for Mystic to be exempted from the clawback provision if the Agreement is extended or if it reenters the market because the ISO-NE market rules change in the future, and such an exemption would contravene Commission precedent and policy.

II. Whether the other terms and conditions of the Mystic Agreement have been shown to be just, reasonable, and not unduly discriminatory?

A. Whether the Constellation LNG-Constellation Mystic Power LLC Fuel Supply Agreement will enable affiliate abuse or have anticompetitive effects in relevant natural gas and electricity markets?

71. [NESCOE's brief does not address this issue.]

B. Whether the proposed level of oversight over Mystic and Everett is appropriate?

72. Because the Agreement shifts risks and costs unreasonably to consumers, its execution requires oversight commensurate with this level of risk and cost exposure.

73. ISO-NE's right to audit Mystic falls short of the oversight required and it would be appropriate for the Commission to consider providing states and other parties with opportunities to monitor the operations and costs of the Mystic Units and EMT, *e.g.*, along the lines of the Connecticut Parties' proposal for management audits.

III. Whether there are other aspects of the proposed rate to be collected under the Mystic Agreement that are not just and reasonable, and whether additional terms and conditions of the Mystic Agreement, or additional transactional rules, should be adopted?

74. Section 2.2.1 of the Agreement should be deleted and Section 2.2 of the Agreement should be modified to ensure that an extension of the Agreement is subject to Commission approval, with a comment opportunity as part of the proceeding. Mystic has indicated that it agrees with these changes.

75. Section 3.6 of the Agreement should be modified to clarify that excess positive Capacity Performance Payments flow to customers.

76. The Agreement's termination provision in Section 2.2.2 is unjust and reasonable because it leaves the ISO with insufficient flexibility to terminate the agreement for unavailability; it should modified to add a winter availability period and a stricter operational metric.

77. Mystic changed the ISO-NE *pro forma* provision addressing notice of forced outages, Section 7.1.2(b), from ten days to 25 days to accommodate its concern about a force majeure event due to a missed shipment.

78. ISO-NE's stated reason for needing to retain the Mystic Units is for fuel security and reliability during the winter months.

79. Section 7.1.2(b) of the Agreement is unjust and unreasonable because it could leave consumers paying for resources that are unavailable during the critical winter months; it should be modified to a three-day period during the winter and a ten-day period at other times.

80. Section 7.1.1 of the Agreement is unjust and unreasonable because it lacks a prohibition on Mystic's taking a planned outage during the winter period.

81. Mystic's modification of Section 7.1.2(e) of the Agreement is unsupported and places unnecessary risk onto consumers; the "best efforts" should be reinstated.

82. Section 3.9 of the Agreement is not just and reasonable because (i) it would permit Mystic to make material modifications to the FSA—modifications which could have significant cost impacts on consumers—without making an FPA section 205 filing at the Commission; and (ii) it appears to allow Mystic to unilaterally change the method for calculating the margin on third-party sales.

83. Mystic has not demonstrated that it is just and reasonable to recover property taxes associated with the Mystic 7 site.

84. Mystic has not demonstrated that it is just and reasonable to recover $12 million in capital expenditures to move the auxiliary boiler from Mystic 7 and relocate it on the Mystic 8 & 9 site.

85. Mystic seeks to recover $8,752,629 in connection with "NERC-CIP" capital expenditures, attributable to the expected change to medium impact facility designation.

86. ISO-NE has not designated Mystic 8 & 9 as necessary to avoid an Adverse Reliability Impact in the planning horizon of more than one year, a necessary component of being classified as a medium impact facility under NERC Reliability Standard CIP-002-5.1a. ISO-NE has not designated Mystic 8 & 9 as such a medium impact facility for any other reason.

CONCLUSION

For the reasons discussed herein, NESCOE respectfully requests that the Commission find that the Agreement as proposed is unjust, unreasonable and unduly discriminatory, and (i) direct changes to the rates to be collected under the Agreement to ensure that it is just and reasonable; (ii) adopt NESCOE's proposed approach and modifications to the Fuel Supply Agreement; (iii) adopt the changes NESCOE recommends to the true-up mechanism in Schedule 3A; (iv) direct Mystic to adopt a balanced clawback mechanism as NESCOE proposes; (v) require changes to the Agreement to enhance customer protections and disallow certain costs that Mystic has not demonstrated to be just and reasonable; and (vi) take other action as the Commission deems appropriate to ensure that the rates, terms and conditions of the Agreement are just and reasonable.

Respectfully Submitted,

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Date: November 2, 2018

Attachment A

NESCOE Redline to
Public Cost-of-Service Agreement,
Mystic Rate Schedule FERC No. 1
(Exh. MYS-0080)

COST-OF-SERVICE AGREEMENT

Table of Contents

COST-OF-SERVICE AGREEMENT

This COST-OF-SERVICE AGREEMENT ("Agreement") is made as of the 15th day of May, 2018, among Constellation Mystic Power, LLC, a Delaware limited liability company ("Owner"), Exelon Generation Company, LLC, a Pennsylvania limited liability company ("Lead Market Participant") and ISO New England Inc., a Delaware non-stock corporation ("ISO").

RECITALS

A. Owner is the owner of Mystic 8 (Asset ID No.1478), a 703.32 MW (summer claimed capability) electrical generating station together with appurtenant facilities and structures, and Mystic 9 (Asset ID No. 1616), a 713.90 MW (summer claimed capability) electric generating station together with appurtenant facilities and structures, both located in Everett, Massachusetts (each a "Resource" and collectively the "Resources").

B. Owner is a wholly-owned, indirect subsidiary of Lead Market Participant, which is a Market Participant in the ISO New England Markets. Lead Market Participant operates and administers the Resources in accordance with the ISO New England Filed Documents and the ISO New England System Rules and causes energy, capacity and ancillary services from the Resources to be offered for sale into the New England Markets.

C. The sole source of fuel for the Resources is ~~Engie North America's~~the liquefied natural gas ("LNG") import terminal located in Everett, Massachusetts (the "LNG Terminal"). In its January 17, 2018 Operational Fuel-Security Analysis, ISO identified the combination of the Resources and the LNG Terminal as one of four key facilities which, in the event of an extended outage, "would result in frequent energy shortages that would require frequent and long periods of rolling blackouts." On March 29, 2018, Lead Market Participant announced an agreement to purchase the LNG Terminal to ensure the continued reliable supply of fuel to the Resources while they remain in operation.

D. ISO is the Regional Transmission Organization for New England and is responsible for the operation of the New England Control Area to ensure short-term reliability and the administration of the New England Markets.

E. Lead Market Participant submitted a Retirement De-List Bid for the Resources for the Forward Capacity Auction for the Capacity Commitment Period starting June 1, 2022 (FCA 13).

F. ISO concluded that the Resources will be needed for reliability purposes during the Term and expects the Resources may be required to run out-of-economic merit order to address fuel security risks that threaten the reliability of the ISO New England transmission system.

G. The Parties have agreed (i) that Owner shall cause an FPA Section 205 proceeding to be initiated to establish the Annual Fixed Revenue Requirement and (ii) to enter into this Agreement for supplying energy, ancillary services and capacity from the Resources into the New England Markets and thereby (x) set the rate by which Owner shall receive its fixed costs for the Resources from Market Participants, (y) govern how the Lead Market Participant shall cause bids to be made, and (z) ensure that the Owner receives its variable costs of supply.

NOW THEREFORE, in consideration of the agreements and covenants set forth herein, and other good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, and intending to be legally bound by this Agreement as of the Effective Date, the Parties covenant and agree as follows:

ARTICLE 1

DEFINITIONS AND RULES OF INTERPRETATION

1.1. Definitions.

Except for the terms defined below and in the attached schedules, capitalized terms shall be as defined in the ISO New England Filed Documents and the ISO New England System Rules.

1.1.1. **"Additional Expenses"** shall mean costs associated with O&M Items in excess of the Fixed O&M Expenses.

1.1.1.a. "**Annual Delivery Program**" is the forecast provided by Owner to Fuel Supplier regarding Owners' annual vaporized LNG requirements.

1.1.2. **"Annual Fixed Revenue Requirement"** or **"AFRR"** shall have the meaning set forth in Schedule 3.

1.1.3. **"Availability"** means the capability of the Resources, in whole or in part, at any given time, to produce energy, capacity, or ancillary services in accordance with Good Utility Practice, and "Available" shall be construed accordingly.

1.1.3a. **"Daily WACOG Price"** shall mean the weighted average cost of all LNG (on an MMBtu basis) in the storage tanks located at the LNG Terminal on the applicable calendar day of delivery.

1.1.4. **"Effective Date"** shall have the meaning set forth in Section 2.1.

1.1.5. **"Fixed O&M Expenses"** shall have the meaning set forth in Schedule 3.

1.1.6. **"Force Majeure Event"** means any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, any order, regulation or restriction imposed by a Governmental Authority, or any other cause beyond a Party's control.

1.1.7. **"Forced Outage"** means any outage of the Resources (other than a Planned Outage) that (i) is taken consistent with Good Utility Practice and applicable NERC criteria and (ii) fully or partially curtails the Resources' ability to supply energy, capacity and/or ancillary services.

1.1.8. **"FPA"** means the Federal Power Act.

1.1.8a **"Fuel Supply Agreement"** or **"FSA"** shall be the Amended and Restated agreement dated July 30, 2018 between Owner and Constellation LNG, LLC ("Fuel Supplier") for the supply of vaporized LNG delivered by Fuel Supplier from the LNG Terminal to Owner.

1.1.8b **"Gas"** shall mean a merchantable mixture of methane and other gaseous hydrocarbons that complies with all applicable industry specifications.

1.1.9. **"Governmental Authority"** means the government of any nation, state or other political subdivision thereof, including any entity lawfully exercising executive, military, legislative, judicial, regulatory, or administrative functions of or pertaining to a government.

1.1.10. **"ISO"** shall have the meaning set forth in the preamble of this Agreement and, where applicable and appropriate, its assignee and/or designee.

1.1.11. **"ISO Market Monitoring"** means the Internal Market Monitor for the ISO.

1.1.12. **"ISO New England Filed Documents"** means the ISO New England Inc. Transmission, Markets and Services Tariff, as may be amended from time to time.

1.1.13. **"ISO New England System Rules"** means all manuals, operating procedures and other requirements of ISO, as each may be amended from time to time.

1.1.14. **"Law"** means any law, treaty, code, rule, regulation, or order or determination of an arbitrator, court or other Governmental Authority, or any license, permit, certificate, authorization, qualification, or approval granted by a Governmental Authority to the extent binding on a Party or any of its property.

1.1.15. **"Lead Market Participant"** shall have the meaning set forth in the preamble of this Agreement and, where applicable and appropriate, its assignee and/or designee.

1.1.16. **“LNG” and “LNG Terminal”** shall have the meanings set forth in the recitals.

1.1.17. **“Month”** means the period beginning at 12:00 a.m. on the first day of the calendar month and ending at 12:00 a.m. of the first day of the next succeeding calendar month.

1.1.18. **“Monthly Reports”** shall have the meaning set forth in Section ~~4.4.4~~4.4.

1.1.19. **“Monthly Settlement”** means the monthly settlement process set forth in the ISO New England System Rules.

1.1.20. **“Notice of Additional Expenses”** shall have the meaning set forth in Section 7.1.2(e).

1.1.21. **“Notice of Forced Outage”** shall have the meaning set forth in Section 7.1.2(b).

1.1.22. **“Notice of Shut-down”** shall have the meaning set forth in Section 7.1.2(c).

1.1.23. **“O&M”** means operations and maintenance.

1.1.24. **“O&M Expenses”** see “Fixed O&M Expenses.”

1.1.25. **“O&M Items”** means fixed O&M costs of repairs of the Resources and replacements of any part of the Resources to correct or avoid any impairment of the capability of the Resources to supply energy, capacity and/or ancillary services, which Owner expenses during the same calendar year in which it is performed, in accordance with Owner’s accounting practices.

1.1.26. **“Owner”** shall have the meaning set forth in the preamble of this Agreement and, where applicable and appropriate, its assignee and/or designee.

1.1.27. **“Party”** means either the ISO or Owner or Lead Market Participant as the context requires, and “Parties,” means ISO and Owner and/or Lead Market Participant, as the context requires.

1.1.28. **“Periodic Cost Report”** shall have the meaning set forth in Section 6.1.1.

1.1.29. **“Planned Outage,”** means a planned interruption, in whole or in part, in the electrical output of a Resource to permit Owner to perform maintenance and repair of the Resource, including O&M Items.

1.1.30. **"Resource(s)"** shall have the meaning set forth in the Recitals.

1.1.31. **"Resource Characteristics"** shall have the meaning set forth in Section 3.4

1.1.32. **"Revenue Credit"** shall have the meaning set forth in Section ~~4.4.1~~4.4.

1.1.33. **"Shut-down"** shall have the meaning set forth in Section 7.1.2(c).

1.1.34. **"Shut-down Date"** shall have the meaning set forth in Section 7.1.2(f).

1.1.35. **"Stipulated Marginal Cost"** shall have the meaning set forth in Section 3.4.

1.1.36. **"Stipulated No-Load Cost"** shall have the meaning set forth in Section 3.4.

1.1.37. **"Stipulated Regulation Offer"** shall have the meaning set forth in Section 3.4

1.1.38. **"Stipulated Start-Up Cost"** shall have the meaning set forth in Section 3.4.

1.1.39. **"Stipulated Variable Cost"** shall have the meaning set forth in Section 3.4.

1.1.40. **"Substitute Unit"** shall have the meaning set forth in Section 7.1.2(b).

1.1.41. **"Supplemental Capacity Payment"** shall have the meaning set forth in Schedule 3.

1.1.42. **"Term"** shall have the meaning set forth in Section 2.1.

1.1.43. **"Variable O&M"** shall be the amount specified in Schedule 1.

1.2. Interpretation.

In this Agreement, unless otherwise indicated or otherwise required by the context, the following rules of interpretation shall apply:

1.2.1. Reference to and the definition of any document (including this Agreement, ISO New England Filed Documents and the ISO New England System Rules) shall be deemed a reference to such document as it may be amended, supplemented, revised, or modified from time to time and any document that is a successor thereto.

1.2.2. The article and section headings, and other captions in this Agreement, are for the purpose of reference only and do not limit or affect its meaning.

1.2.3. Defined terms in the singular shall include the plural and vice versa, and the masculine, feminine or neuter gender shall include all genders.

1.2.4. Accounting terms used herein shall have the meanings given to them under generally accepted accounting principles within the United States consistently applied.

1.2.5. The term "including" when used herein shall be by the way of example only and shall not be considered in any way a limitation.

1.3. Construction.

This Agreement has been drafted by the Parties hereto and shall not be construed against any Party as the sole drafter.

ARTICLE 2

TERM

2.1. Effective Date and Term.

Subject to the terms of this Section 2.1, this Agreement shall be effective at the beginning of the operating hour ending at 1:00 a.m., June 1, 2022 (the "Effective Date") and shall terminate at the end of the operating hour beginning at 11:00 p.m. as of the date of the termination as provided in Section 2.2 ("Term"). As conditions precedent to the effectiveness of this Agreement, (i) the Commission must issue an order accepting the terms of the Agreement and establishing the Annual Fixed Revenue Requirement ("AFRR") by December 21, 2018; and (ii) each of the Parties must re-execute this Agreement by January 3, 2019 as written confirmation that the Party accepts the Commission-approved Agreement and AFRR. If either of the foregoing conditions precedent is not met, this Agreement shall be deemed ineffective and any signatures hereto shall be rescinded.

2.2. Termination.

This Agreement may be terminated as follows:

Once this Agreement is effective, it shall remain in effect for ~~at least~~ two 12-month Capacity Commitment Periods and shall terminate ~~no sooner than~~on May 31, 2024. Owner or Lead Market Participant shall provide timely notice of any such termination of this Agreement to the Commission. Nothing in this Agreement shall limit the ability of the Owner or Lead Market Participant, by mutual consent of the Parties prior to the commencement of the Term, to seek to terminate this Agreement by making a filing with the Commission in accordance with the Federal Power Act.

~~2.2.1. In order to meet a reliability need, ISO-NE may elect to continue this Agreement beyond its two-Capacity Commitment Period term for subsequent Capacity Commitment Periods upon written notice given no later than the March 1 that is 39 months prior to the start of the subsequent Capacity Commitment Period. Owner shall confirm within 15 days of receipt of ISO-NE's notice that it is willing and able to extend the term.~~

2.2.1. [PROVISION DELETED]

~~2.2.1.~~2.2.2. Upon 30 days' notice to the Owner and Lead Market Participant, the ISO may unilaterally terminate this Agreement if, over the twelve (12) month period preceding the notice or during any three (3) month period from December through February, the ISO determines that the average value over all hours in that period of the ratio of the Resource's or Resources' Economic Maximum Limit (as it may be redeclared from time to time) to the Resource's or Resources' Capacity Supply Obligation is less than ~~fifty~~seventy-five percent (~~50~~75%). Owner and Lead Market Participant shall retain all of their existing rights to challenge the ISO's calculation of the aforementioned ratio under the ISO Billing Policy.

~~2.2.2.~~2.2.3. This Agreement may be terminated as provided in Section 7.1.2, Section 9.2 and Section 11.4.

2.3. Consequence of Termination or Expiration.

Inasmuch as the Lead Market Participant submitted a Retirement De-List Bid, the Parties acknowledge that, upon termination, the provisions of Market Rule 1 Section III.13 applicable to resources that have submitted Retirement De-List Bids and been retained for reliability or fuel security shall apply.

2.4. Survival.

Notwithstanding the termination of this Agreement, the Parties shall continue to be bound by the provisions of this Agreement which by their nature are intended to, and shall, survive such termination.

ARTICLE 3
RIGHTS AND OBLIGATIONS

3.1. In General.

During the Term, the Resources will be listed Generating Capacity Resources with Capacity Supply Obligations. The Resources' Capacity Supply Obligations shall be in the amount of their summer Qualified Capacity (specifically 703 MW for Mystic 8 and 714 MW for Mystic 9) during all months except for December, January, and February, during which months their Capacity Supply Obligation shall equal the Resources' winter Qualified Capacity (specifically 842 MW for Mystic 8 and 858 MW for Mystic 9). The Owner and Lead Market Participant shall operate, maintain and administer the Resources in accordance with (a) this Agreement, (b) the ISO New England Filed Documents, (c) the ISO New England System Rules, and (d) Good Utility Practice, as applicable. Nothing herein shall be construed to require the Owner or Lead Market Participant to take action that is contrary to Good Utility Practice.

3.2. Insurance.

Owner or Lead Market Participant shall arrange for and maintain an appropriate level of liability and property insurance with respect to the Resources consistent with Good Utility Practice.

3.3. Bilateral Agreements.

The Resources will not be subject to any bilateral agreement for the sale or control of energy or ancillary services from the Resources, unless the Owner or Lead Market Participant provides the ISO with a copy of the proposed agreement at least 30 days in advance of the agreement's effective date and obtains ISO's prior written consent. If ISO does not respond within 30 days, ISO will be deemed to have consented. Notwithstanding the foregoing, during the Term, Owner or Lead Market Participant shall only have the ability to purchase replacement capacity for periods during which the Resource(s) (i) are on ISO-approved Planned Outage(s) or, (ii) are on Forced Outage(s) and ISO has approved the purchase of replacement capacity.

3.4. Supply Offers.

For each day, the Lead Market Participant shall offer for sale energy and ancillary services (which include Regulation and Reserves) into the New England Markets from the Resources, based on the characteristics and operating parameters specified in Schedule 2 (the "Resource Characteristics") and consistent with the ISO New England Filed Documents and ISO New England System Rules. Supply Offers shall be equal to the Stipulated Variable Costs as provided below. Supply Offers also shall not exceed Energy Market Reference Levels as determined using the marginal cost formulas specified in Appendix A to Market Rule 1 of the Tariff. Lead Market Participant shall use commercially reasonable efforts to cause the submittal of Supply Offers for Economic Minimum Limit and Economic Maximum Limit that are consistent with ambient air forecasts and /or environmental permit parameters. Lead Market Participant also shall offer Regulation into the New England Markets from the Resource based on the Resource Characteristics using only Stipulated Regulation Offers as defined below.

3.4.1. The Stipulated Variable Costs shall be self-adjusting formulary rates accepted by the Commission pursuant to the FPA Section 205 proceeding initiated by Owner. The inputs to the formula below shall be updated daily or at the most frequent time interval permitted under the ISO New England System Rules. Stipulated Variable Costs shall be determined according to the definitions below using parameter values from Schedule 1.

Stipulated Variable Cost = Stipulated Start Up +Stipulated No Load + Stipulated

Marginal

Cost **Cost** **Cost**

<u>Where</u>

Stipulated Start Up Cost = Start-Up Fuel x Fuel Price + Start-Up O&M + Station Service ($) (MMBtu) ($/MMBtu) ($)

Stipulated No-Load Cost = No-Load Fuel x Fuel Price + No Load O&M ($/hr) (MMBtu/hr) ($/MMBtu) ($/hr)

Stipulated Marginal Cost = Incremental Heat Rate x Fuel Price + Variable O&M ($/MWh) (MMBtu/MWh) ($/MMBtu) ($/MWh)

<u>And</u>

Fuel Price = Fuel Index + Fuel Variable/ + Emissions Cost + Fuel Opp. Cost + Op Permit Adder
Price Other Costs
($/MMBtu) ($/MMBtu) ($/MMBtu) ($/MMBtu) ($/MMBtu)

Station Service = Station Service x Energy Price
(S) (MWh) from Schedule 1 ($/MWh)

Emissions Cost = Emissions Rates x Applicable Emissions Price
($/MMBtu) (lbs/MMBtu) ($/ton)

3.4.1.1 "Applicable Emission Price" shall mean the applicable emissions allowance price ($/ton) from Evolution Markets Inc. (or successor) converted to pounds ($/lbs) using appropriate pounds/ton conversion ratio.

3.4.1.2 "Energy Price" shall mean cost of energy used to supply station service, calculated using a method permitted under ISO New England Filed Documents and ISO New England System Rules.

3.4.1.3 "Fuel Index Price" shall mean the ~~current daily price determined using a world LNG index or, alternatively~~ <u>Daily WACOG Price times Gas delivered by Fuel Supplier to Owner</u>, and subject to approval by <u>the</u> ISO Market ~~Monitoring, the weighted average cost of gas in the storage tank adjacent to the LNG Terminal~~<u>Monitor</u>.

3.4.1.4 "Fuel Opportunity Cost" or "Fuel Opp. Cost" shall mean the amount, if any, as requested by the Fuel Supplier, and as approved by the ISO Market Monitor, and applicable to all or a specified amount of fuel, based upon either (i) the amount, if any, by which the ~~AGT (citygate) fuel index price~~Algonquin, city-gates, Midpoint, as provided for in Gas Daily, Daily Price Survey ("Algonquin, city-gates") exceeds the Fuel Index Price~~, and/~~ for that calendar day, or (ii) the opportunity cost ~~associated with a limited supply of fuel, as approved by ISO and ISO Market Monitoring~~requested by Fuel Supplier for fuel conservation purposes.

3.4.1.5 "Fuel Variable/Other Costs" shall mean the additional amount, if any, to be added to the Fuel Index Price to reflect other costs associated with the Fuel Index Price to properly reflect the cost of delivered fuel at the LNG Terminal. Fuel Variable/Other Costs shall be subject to approval of ISO Market Monitoring.

3.4.1.6 "Operating Permit Adder" shall mean either: (i) the opportunity cost associated with the limit on emissions contained in the operating permit and/or (ii) the cost associated with exceeding the emissions rate contained in the operating permit.

3.4.1.7 "Stipulated Regulation Offer" shall mean the actual offer for providing Regulation from the Resource, subject to any cap specified in Market Rule 1, as may be amended from time to time.

3.5. Self-Scheduling.

~~As long as a fuel limitation does not result, and subject~~Subject to the ISO New England System Rules, the ISO New England Operating Documents and the compensation provisions of Article 4, the Lead Market Participant may request to self-schedule the Resources for operational and maintenance considerations, including testing~~, and fuel~~. In addition, the Fuel Supplier may request self-scheduling for tank management purposes. ~~Alternatively, rather than self-scheduling for fuel management purposes, the Owner's affiliate shall sell fuel to third parties or reject a fuel shipment if Owner and/or~~Any energy market losses Lead Market Participant ~~reasonably believes that action will reduce overall costs to ratepayers~~incurs as a direct result of self-scheduling associated with Fuel Supplier's request shall result in credits against the charges under the FSA. ISO System Operations may accept or not accept the self-schedule in its sole discretion.

3.6 Capacity Performance Payments.

The Resources shall be subject to negative Capacity Performance Payments and eligible for positive Capacity Performance Payments consistent with other ~~Resources~~resources with Capacity Supply Obligations; provided, however, that positive Capacity Performance Payments shall be used solely as a credit against negative Capacity Performance Payments and shall not otherwise accrue to the benefit of the Resources, but net negative Capacity Performance Payments shall affect the amount of the Revenue Credit. Specifically:

i. Within each month, positive Capacity Performance Payments accrued by a Resource can be used to offset negative Capacity Performance Payments (i) accrued by either Resource and (ii) not otherwise reimbursed by Fuel Supplier under the FSA, creating a net monthly Capacity Performance Payment position for both Resources, which may be positive or negative ("Net Monthly Station Position").

ii. During the first two months of a Capacity Commitment Period, the Net Monthly Station Position for the second month of the Capacity Commitment Period shall be added to the first, creating an "Accrued Penalty Balance" for the month of July. Thereafter, at the end of each month within the Capacity Commitment Period, the Accrued Penalty Balance shall be calculated as the prior month's Accrued Penalty Balance plus the current month's Net Monthly Station Position; provided, however, that for the month of June of each Capacity Commitment Period, the prior month's Accrued Penalty Balance shall be zero and June's Accrued Penalty Balance shall be equal to its Net Monthly Station Position.

iii. If the prior month's Accrued Penalty Balance is zero or negative, and the current month's Net Monthly Station Position is negative or zero, then the Revenue Credit for the month shall be increased by the amount of the absolute value of the Net Monthly Station Position, thereby charging any negative Capacity Performance Payment to the Owner.

iv. If the prior month's Accrued Penalty Balance is negative, and the current month's Net Monthly Station Position is positive, then the Revenue Credit for the month shall be reduced by the lesser of the Net Monthly Station Position and the absolute value of the prior month's Accrued Penalty Balance.

v. If the prior month's Accrued Penalty Balance is positive and the current month's Net Monthly Station Position is negative, and the prior month's Accrued Penalty Balance is greater than or equal to the absolute value of the current month's Net Monthly Station Position, then there will be no adjustment to the Revenue Credit for that month. If the absolute value of the Net Monthly Station Position exceeds the prior month's Accrued Penalty Balance, then the Revenue Credit shall be increased by the amount by which the absolute value of the Net Monthly Station Position exceeds the prior month's Accrued Penalty Balance.

vi. If the prior month's Accrued Penalty Balance is zero or positive and the current month's Net Monthly Station Position is zero or positive, there shall be no adjustment to the Revenue Credit for that month.

vii. Notwithstanding the foregoing, any positive Accrued Penalty Balance shall be reset to $0 on each December 1. For the avoidance of doubt, the Resources shall not be permitted to apply positive Accrued Penalty Balances from one Capacity Commitment Period to another.

3.7 Winter Fuel Security Penalty.

From December 1 through the last day of February, the Resources shall be subject to an additional Winter Fuel Security Penalty when the following three conditions are met: (i) Capacity Scarcity Conditions exist and either or both Resources have a Capacity Performance Score that is negative, (ii) the volume in the storage tank at the LNG Terminal at 8 a.m. of the day during which the interval occurred is less than 510,000 MCF, provided that, if the interval occurs between 48 hours and 6 hours in advance of the next scheduled arrival of an LNG cargo, this minimum volume requirement shall be 375,000 MCF, and provided further, that if the interval occurs less than 6 hours in advance of the next ~~schedule~~scheduled arrival of an LNG cargo, this minimum tank volume shall be 330,000 MCF, and (iii) the amount calculated by subtracting the mid-point price, in $/MMBtu, for the Henry Hub, as published in Platt's Gas Daily for the gas day in which the Capacity Scarcity Condition occurred, from the mid-point price, in $/MMBtu, for the Algonquin ~~City-Gates, as published in Platt's Gas Daily for the relevant day,~~, city-gates is greater than $17.50/MMBtu (the "Winter Fuel Security Penalty"). The penalty rate shall be equal to the sum of the System Ten Minute Spinning Reserve (System TMSR), System Ten Minute Non- Spinning Reserve (TMNSR), and System Ten Minute Operating Reserve (System TMOR) Reserve Constraint Penalty Factors applied at the Node or Nodes at which the Mystic units are settled during the interval in which Capacity Scarcity Conditions exist, calculated consistent with Section III.2.7A(a-e) of the Tariff, using the following stated values: System TMSR of $50/MWh, TMNSR of $1,500/MWh, and System TMOR of $1,000/MWh. Any Winter Fuel Security Penalty shall be calculated in the same manner as Capacity Performance Payments (i.e., consistent with Sections III.13.7.2.2., III.13.7.2.3, III.13.7.2.4), with the exception that the calculations will not be on a Resource-specific basis but with the two Resources' Capacity Performance Scores combined to form a single Capacity Performance Score for the Mystic station. The maximum penalty that can be assessed in any month pursuant to Section 3.6 and 3.7 shall be $18.49 million, except for the months of December, January, and February, where the maximum assessed penalty in any month shall be $30 million. The maximum penalty assessed pursuant to these Sections 3.6 and 3.7 shall not exceed $110.30 million per Capacity Commitment Period.

3.8 Fuel Supply Information Sharing.

The Lead Market Participant shall provide ISO with a 24/7 Operations contact for the LNG Facility and will authorize that contact to promptly provide ISO with operational information reasonably requested by ISO, including storage tank volumes, scheduled LNG cargoes, and outages of the LNG Facility. In addition, Lead Market Participant shall provide ISO with a daily report regarding (i) storage tank inventory, (ii) next scheduled LNG cargo ~~(~~expected ~~amount in MMBtu)~~arrival date and volume, and (iii) expected aggregate LNG sendout of (a) third party sales of both vapor (by pipeline) and (b) liquid (by truck) leading up to the LNG ~~for that day~~cargo arrival date.

3.9 Fuel Supply Management~~ and Third-Party Sales~~. The Owner, Lead Market

Participant and their affiliates, and Fuel Supplier shall exercise Good Utility Practice with respect to the fuel supply arrangements for the Resources. Owner~~, which is a party to a Fuel Supply Agreement with Constellation LNG, LLC for the supply of fuel to Mystic 8 & 9~~ and Fuel Supplier, who are parties to the FSA, shall not modify any material term of that Agreement without providing ISO ~~with~~ a copy of the proposed modification and submitting a request under Section 205 of the FPA with the Commission. With respect to any modification to the conceptual method for calculating the Annual Reliability Charge paid under the FSA, such modification shall not take effect until Owner obtains ISO's prior written consent and submits an informational filing to the Commission, in the docket in which this Cost of Service Agreement is approved, that shows the proposed modifications at least 15 days in advance of the modification's effective date~~ and, with respect to any modification to the conceptual method for calculating any margin earned on any third-party sales of LNG re-gasified through the LNG Facility, obtains ISO's prior written consent~~. Owner and Lead Market Participant and/or their affiliates shall meet with ISO (i) prior to the commencement of the Term of this Agreement to discuss the fuel supply plan, including but not limited to the Annual Delivery Program, for the first twelve months of the Term, and (ii) prior to September 1 of each year of the Term to discuss the overall fuel supply plan (i.e., the number of cargos scheduled for both Mystic and third-party sales) for the Winter months of December through March. To the extent that the fuel supply plan is modified after the meeting with ISO (such as through the addition~~ or~~, subtraction, delay, advancement or quantity change of a scheduled LNG cargo), Owner or Lead Market Participant will provide timely notice of same to ISO~~.~~

3.10 Minimization of Out-Of-Market Impacts.

The Lead Market Participant shall cooperate with ISO in good faith, in light of the fuel supply available to the Resources, to minimize the market impacts of reliability commitments in the energy market.

ARTICLE 4

COMPENSATION AND SETTLEMENT

4.1. In General.

The Lead Market Participant is subject to charges and credits for services in the New England Markets, including the Supplemental Capacity Payment, in accordance with the ISO New England System Rules and the ISO New England Filed Documents, with settlement taking place in the normal weekly and monthly settlement processes as they may be amended from time to time. The Supplemental Capacity Payment shall be settled through the account of the Lead Market Participant. The Lead Market Participant and the Owner must comply with all ISO requirements for customer and asset registration.

4.2. Variable Cost Recovery.

In order to provide for recovery of variable costs, the Supply Offers applicable to the Resources as determined in accordance with Section 3.4. shall be included in the calculation of Net Commitment Period Compensation (“NCPC”) and the Revenue Credit as defined below. All NCPC shall be paid in accordance with applicable ISO settlement procedures. In addition, to the extent that Mystic’s actual fuel costs differ from sum of the “Fuel Index Price” and/or the “Fuel Variable/Other Cost” components of its “Stipulated Variable Costs” approved by ISO Market Monitoring, and such difference precludes Buyer from recovering its actual fuel costs because of the operation of the Revenue Crediting mechanism in Section 4.4, the difference between Mystic’s actual fuel costs for such month and the amount Mystic is permitted to recover for fuel in its Stipulated Variable Costs for such month shall be added to the following month’s Fuel Supply Cost.

4.3. Fixed-Cost Recovery.

Lead Market Participant shall be entitled to a Supplemental Capacity Payment for the Resource for each Month, calculated in accordance with Schedule 3, which ISO shall cause to be paid by Participants through the monthly settlement process for the New England Markets. The Annual Fixed Revenue Requirement shall be as determined by the

Commission pursuant to an FPA Section 205 proceeding initiated by Owner.

4.4. Revenue Credit.

~~4.4.1. In General.~~ All revenues related to the ~~Resources less the Stipulated Variable Costs (“~~Revenue Credit~~”)~~ shall reduce the Supplemental Capacity Payment in accordance with the formulas in Schedule 3. The Revenue Credit shall include:

~~4.4.2. Capacity Base Payments and Capacity Performance Payments. The Revenue Credit shall include~~

(1) All revenues related to (i) the Capacity Base Payment, as determined in accordance with the Tariff, ~~and~~ (ii) the net negative Capacity Performance Payments as determined in accordance with Section 3.6 above~~. The~~, and (iii) the Capacity Base Payment which shall be calculated as the product of the Resources’ combined summer Qualified Capacity for the applicable Capacity Commitment Period and the Capacity Clearing Price in the appropriate Capacity Zone. For the avoidance of doubt, Lead Market Participant shall not receive Capacity Performance Payments (positive or negative) calculated pursuant to the Tariff, and shall instead only receive Capacity Performance Payments calculated pursuant to Section 3.6 above~~.~~, plus

~~4.4.3. Revenues Received in the New England Markets.~~

(2) All revenues related to the Resources earned in the New England Markets settled by ISO (in addition to the revenues earned in the Forward Capacity Market above), less the ~~Stipulated Variable Cost of producing those revenues as represented by the Supply Offers and less the~~ variable costs of producing revenues for Regulation as represented by the Stipulated Regulation Offer, ~~shall be included in the calculation of the Revenue Credit. Inframarginal revenue shall be reduced for Stipulated Variable Costs in excess of hourly revenue to the extent that the unit was self-scheduled in order to manage fuel delivery obligations. Monthly inframarginal revenue is the sum of all daily~~

~~inframarginal revenue values. If the revenues related to the Resources are not paid on a Resource specific basis, the ISO shall allocate such revenues to the Resources that are subject to this Agreement.~~plus

~~4.4.4. Other Revenues. Any~~

(3) Any other revenues related to the Resources' sales that have not been settled by ISO (including from bilateral agreements, emission credits, release of firm transportation arrangements, sale of surplus equipment, etc.), less any incremental costs directly related to securing additional revenue that are not already accounted for in the Annual Fixed Revenue Requirement or Stipulated Variable Costs, will be included in the Revenue Credit or FSA. These incremental costs may not be greater than the incremental revenues on a case- by-case basis. The Owner or Lead Market Participant shall report all such other revenues, or the absence thereof, to ISO in a monthly report (the "Monthly Report").

ARTICLE 5
MARKET MONITORING

5.1. Mitigation.

Although this Agreement provides for Supply Offers that do not exceed thresholds identified in Appendix A, Market Rule 1, nothing herein shall preclude the ISO from otherwise applying any provision of Appendix A or Appendix B to Market Rule 1 to Owner, Lead Market Participant, or any Affiliate of either, the Resources, or any other resources of Owner, Lead Market Participant, or any Affiliate thereof, including mitigation of Supply Offers for Resources covered by this Agreement to the applicable Stipulated Variable Cost as defined in Section 3.4 and Schedule 1.

5.2. Adjustment.

Subject to prior consultation with the Lead Market Participant, Supply Offers that exceed Stipulated Variable Cost will be automatically adjusted by ISO Market Monitoring to Stipulated Variable Cost.

ARTICLE 6
REPORTING

6.1. Variable Cost and Resource Characteristic Reporting.

6.1.1. Owner or Lead Market Participant shall update the components of Stipulated Variable Costs that are not publicly available as they may change from time to time on a timely basis, along with supporting information as requested, in a format approved by ISO and consistent with the formulas provided in Section 3.4 and Schedule 1 (the “Periodic Cost Report”). If Owner or Lead Market Participant fails to provide updated information on a timely basis, Supply Offers may be adjusted to Stipulated Variable Costs based on the information on file. ISO will give Owner 30 days’ prior written notice of any change in the form of the Periodic Cost Report.

6.1.1. The Resource Characteristics applicable to the Resources during the Term are set forth in Schedule 2 hereto. Owner or Lead Market Participant shall provide ISO with updated Resource Characteristics set forth on a revised Schedule 2 immediately upon any change of those Resource Characteristics. If ISO does not agree to the revised Schedule, the Schedule in effect shall remain in effect during the Term pending alternative dispute resolution in accordance with Appendix D to Market Rule 1.

6.2. Books and Records; Audit Rights.

ISO shall have the right, at any time upon reasonable notice, to examine at reasonable times the books and records of Owner and Lead Market Participant to the extent necessary to audit and verify the accuracy of all reports, statements, invoices, charges, or computations pursuant to this Agreement. The Parties acknowledge and agree that ISO may perform audits of the Monthly Reports and the Periodic Cost Reports as well as a final audit of all expenses incurred under this Agreement upon completion of the Term. Owner or Lead Market Participant’s affiliates shall exercise reasonable efforts to secure the ability to provide ISO, subject to a non-disclosure agreement, copies of any contracts between Owner or Lead Market Participant's Affiliates and third-parties for the sale of fuel from the LNG Facility during the Term and any contracts between Owner or Lead Market Participant's Affiliates and third parties for the supply of fuel to the LNG Facility during the Term. Upon ISO request, Owner or Lead Market Participant also shall provide copies of any ~~affiliate~~ fuel supply agreements involving the LNG Terminal in effect during the Term~~ and documentation of the margin earned on any third-party sales of LNG re-gasified through the LNG Facility for purposes of verifying the crediting of such margin against the cost of the Resources' fuel supply from Constellation LNG, LLC~~. All information provided during the course of such an examination shall be treated as confidential information under the ISO New England Information Policy and any other applicable ISO Protocols.

ARTICLE 7

RESOURCE OPERATION AND MAINTENANCE

7.1. Planned and Forced Outages.

7.1.1. Planned Outages. Except during the period from December to February, Lead Market Participant shall be entitled to take one or both of the Resources out of operation or reduce the net capability of one or both of the Resources during Planned Outages, in accordance with the schedule for Planned Outages as established and implemented pursuant to the ISO New England System Rules, the Transmission, Markets and Services Tariff and the MPSA.

7.1.2. Forced Outages.

(a) Generally. Lead Market Participant shall be entitled to take the Resources out of operation or reduce the net capability of the Resources upon the occurrence of a Forced Outage.

(b) Notice of Forced Outage. In the event of a Forced Outage that is anticipated to last for more than ~~twenty-five~~ten (~~25~~10) days (or more than three (3) days during the months December – February), in addition to any other notification obligation arising under ISO New England System Rules, the Transmission, Markets and Services Tariff and the MPSA, Lead Market Participant shall promptly notify ISO in writing of its occurrence, estimated duration, and whether Additional Expenses are expected to be required to return the Resource(s) to service (a “Notice of Forced Outage”). Lead Market Participant shall also inform ISO of the availability of any previously retired unit (the “Substitute Unit”) and the costs and time required to bring the Substitute Unit back into service and to retire the Resource(s) on Forced Outage.

(c) Notice of Shut-down. As soon as reasonably practicable after the date of a Notice of Forced Outage but in no event greater than thirty (30) days from the start of such Forced Outage, any Party may, after assessing the nature, expected duration, and expected incurrence of Additional Expenses, notify the other Parties in writing of its determination that the Resource(s) shall, subject to the provisions of Section 7.1.2(e), be Shut-down (a “Notice of Shut-down”) and if such notice applies to the entirety of both Resources that this Agreement should be terminated.

(d) Supplemental Capacity Payment. In the event that either of the Resources is Shut-down, Owner or Lead Market Participant shall only remain entitled to receive the Supplemental Capacity Payment based on the AFRR through the Shut-down Date; provided that with respect to a Shut-down applying only to a unit, Owner shall have the right but not the obligation to terminate this Agreement. If Owner or Lead Market Participant opts not to terminate this Agreement, Owner or Lead Market Participant may file amendments to the AFRR with the Commission.

(e) Option to Approve Additional Expenses. With respect to a Notice of Shut-down made by Lead Market Participant, if within thirty (30) days of receipt of Lead Market Participant’s Notice of Shut-down ISO provides written notice to Lead Market Participant that it is willing to pass through for payment by the Participants in the Monthly Settlement process of the New England Markets such Additional Expenses (a “Notice of Additional Expenses”) that may be required to recover from such Forced Outage, Lead Market Participant agrees that it will, with reasonable dispatch, take the action requested by ISO, i.e., not Shut-down the Resource(s) and make such Additional Expenses as paid to it by the Participants to return the Resource(s) to service from such Forced Outage, or make such expenditures as paid to it by the Participants to bring the Substitute Unit into service and retire the Resource(s) on Forced Outage. The Parties agree that a Notice of Additional Expenses shall be immediately effective, and Lead Market Participant shall be entitled to begin receiving payments from ISO pursuant thereto, as of the day following the date the Owner or Lead Market Participant files a request under Section 205 of the FPA with the Commission to recover from ISO the Additional Expenses identified in the Notice of Additional Expenses. Payments will be made subject to refund pending the approval of such Additional Expenses by the Commission. The Parties further agree that Lead Market Participant is obligated to use ~~commercially reasonable~~ its best efforts to minimize Additional Expenses and that the amounts approved under the Notice of Additional Expenses are subject to offset by any proceeds from any and all third-party sources, including insurance proceeds, paid to Lead Market Participant to return the Resource(s) from the Forced Outage. Lead Market Participant shall make a subsequent reconciliation ("true-up") filing with the Commission and refund any payments for Additional Expenses paid to Lead Market Participant that are disallowed by the Commission, or that exceed the amount actually expended by the Lead Market Participant, after offsets.

(f) Shut-down Date. With respect to a Notice of Shut-down issued by ISO pursuant to Section 7.1.2(c), the "Shut-down Date" shall be that date ten (10) days after the receipt of such Notice of Shut-down by the Owner. With respect to a Notice of Shut-down issued by Lead Market Participant pursuant to Section 7.1.2(c), the "Shut-down Date" shall be that date thirty (30) days after the receipt of such Notice of Shut-down by ISO unless ISO has issued a Notice of Additional Expenses in accordance with Section 7.1.2(e), in which case no Shut-down Date will have occurred with respect to such Notice of Shut-down or the Shut-down Date will be the date on which the Substitute Unit is brought back into service. As of the Shut-down Date, the interconnection rights for the Resource(s) shall terminate and the status of the Resource will be converted to retired.

7.2. Additional and Other Expenses.

Except as provided for in Section 7.1, Owner and Lead Market Participant shall (i) not be required or otherwise obligated to incur any Additional Expenses and (ii) not be required to enter into any additional agreements or incur any additional costs, including fixed-fuel costs, that Owner is not already obligated to enter into, or incur, as the case may be, that are not otherwise contemplated by, and being recovered by Owner Lead Market Participant pursuant to, the Annual Fixed Revenue Requirement. To the extent that ISO provides notice of shut-down pursuant to 7.1.2(f) and such notice will result in Owner's or Lead Market Participant's failure to recover certain costs that were reasonably incurred for operation of Resources and that are unable to be avoided using commercially reasonable efforts, Owner or Lead Market Participant shall be entitled to make a Section 205 filing to recover those costs at the Commission.

ARTICLE 8
FORCE MAJEURE EVENTS

8.1. Notice of Force Majeure Event.

If either Party is unable to perform its obligations under this Agreement due to a Force Majeure Event, the Party unable to perform shall promptly notify the other Party.

8.2. Effect of Force Majeure Event.

8.2.1. If the Availability of the Resource is reduced by reason of a Force Majeure Event, Section 7.1.2 shall apply (i.e., a Force Majeure Event shall be deemed to create a Forced Outage). Subject to reduction as explicitly set forth in this Agreement and to Sections 7.1.2, 9.2, and 11.4, Lead Market Participant shall continue to receive the Supplemental Capacity Payment without any other reduction while the Force Majeure Event continues.

8.2.2. Neither Party will be considered in default as to any obligation under this Agreement if prevented from fulfilling the obligation due to an event of Force Majeure. Notwithstanding the foregoing, no event of Force Majeure affecting either Party shall excuse that entity from any payment, charge, penalty, financial consequence or settlement responsibility that it is obligated to make hereunder. A Party whose performance is hindered by an event of Force Majeure shall make all reasonable efforts to perform its obligations.

8.3. Remedial Efforts.

The Party unable to perform by reason of a Force Majeure Event shall use reasonable efforts to remedy its inability to perform and to mitigate the consequences of the Force Majeure Event as soon as reasonably practicable; provided that (i) no Party shall be required to settle any strike, walkout, lockout, or other labor dispute on terms which, in the Party's sole discretion, are contrary to its interests and (ii) subject to Sections 7.1.2 and 7.2, the Party unable to perform shall, as soon as practicable, advise the other Party of the reason for its inability to perform, the nature of any corrective action needed to resolve performance, and its efforts to remedy its inability to perform and to mitigate the consequences of its inability to perform and shall advise the other Party of when it estimates it will be able to resume performance of its obligations under this Agreement.

ARTICLE 9

REMEDIES

9.1. Damages and Other Relief.

9.1.1. Liability of ISO. ISO shall not be liable to Owner or Lead Market Participant for actions or omissions by ISO in performing its obligations under this Agreement, provided it has not willfully breached this Agreement or engaged in willful misconduct. To the extent Owner or Lead Market Participant has claims against ISO, Owner or Lead Market Participant may only look to the assets of ISO for the enforcement of such claims and may not seek to enforce any claims against the directors, members, officers, employees or agents of ISO who, Owner and Lead Market Participant acknowledge and agree, have no personal liability for obligations of ISO by reason of their status as directors, members, officers, employees or agents of ISO.

9.1.2. Liability of Owner. Except as explicitly provided herein, Owner and Lead Market Participant shall not be liable to ISO for actions or omissions by Owner or Lead Market Participant in performing their obligations under this Agreement, provided that Owner or Lead Market Participant has not willfully breached this Agreement or engaged in willful misconduct.

9.1.3. Limitation of Liability. In no event shall Owner or Lead Market Participant be liable to ISO or ISO be liable to Owner or Lead Market Participant for any incidental, consequential, multiple or punitive damages, loss of revenues or profits, attorneys' fees or costs arising out of, or connected in any way with the performance or non-performance of this Agreement.

9.1.4. Indemnification. Owner and Lead Market Participant shall indemnify, defend and save harmless ISO and its directors, officers, members, employees and agents from any and all damages, losses, claims and liabilities by or to third parties arising out of or resulting from the performance by ISO under this Agreement or the actions or omissions of Owner and Lead Market Participant in connection with this Agreement, except in cases of gross negligence or willful misconduct by ISO or its directors, officers, members, employees or agents.

9.2. Termination for Default.

If ISO shall fail to perform any material obligation imposed on it by this Agreement and that obligation has not been suspended pursuant to this Agreement, Owner or Lead Market Participant, at its option, may terminate this Agreement by giving ISO written notice setting out specifically the circumstances constituting the default and declaring its intention to terminate this Agreement. If Owner or Lead Market Participant shall fail to perform any material obligation imposed on it by this Agreement and that obligation has not been suspended pursuant to this Agreement, ISO may terminate this Agreement by giving Owner and Lead Market Participant written notice setting out specifically the circumstances constituting the default and declaring its intention to terminate this Agreement. If the Party receiving the notice does not within ten (10) days after receiving the notice, remedy the default, the Party not in default shall be entitled by a further written notice to terminate this Agreement. The Party not in default shall have a duty to mitigate damages. Termination of this Agreement pursuant to this Section 9.2 shall be without prejudice to the right of any Party to collect any amounts due to it prior to the time of termination.

9.3. Waiver.

The failure to exercise any remedy or to enforce any right provided in this Agreement or applicable Law shall not constitute a waiver of such remedy or right or of any other remedy or right. A Party shall be considered to have waived any remedies or rights only if the waiver is in writing.

9.4. Beneficiaries.

Except as is specifically set forth in this Agreement, nothing in this Agreement, whether express or implied, confers any rights or remedies under, or by reason of, this Agreement on any persons other than the Parties and their respective successors and assigns, nor is anything in this Agreement intended to relieve or discharge the obligations or liability of any third party, nor give any third person any rights of subrogation or action against any Party.

ARTICLE 10

COVENANTS OF THE PARTIES

10.1. ISO represents and warrants to Owner and Lead Market Participant as follows:

10.1.1. ISO is a validly existing corporation with full authority to enter into this Agreement.

10.1.2. ISO has taken all necessary measures to have the execution and delivery of this Agreement authorized, and upon the execution and delivery of this Agreement, this Agreement shall be a legally binding obligation of ISO.

10.1.3. ISO has all regulatory authorizations necessary for it to perform its obligations under this Agreement.

10.1.4. The execution, delivery, and performance of this Agreement are within ISO's powers and do not violate any of the terms and conditions in its governing documents, any contracts to which it is a party, or any Law applicable to it.

10.2. Owner represents and warrants to ISO as follows:

10.2.1. Owner is a validly existing entity with full authority to enter into this Agreement.

10.2.2. Owner has taken all necessary measures to have the execution and delivery of this Agreement authorized, and upon the execution and delivery of this Agreement, this Agreement shall be a legally binding obligation of Owner.

10.2.3. Owner has, or has applied for, all regulatory authorizations necessary for it to perform its obligations under this Agreement.

10.2.4. The execution, delivery, and performance of this Agreement are within the Owner's powers and do not violate any of the terms and conditions in its governing documents, any contracts to which it is a party, or any Law applicable to it.

10.3. Lead Market Participant represents and warrants to ISO as follows:

10.3.1. Lead Market Participant is a validly existing entity with full authority to enter into this Agreement.

10.3.2. Lead Market Participant has taken all necessary measures to have the execution and delivery of this Agreement authorized, and upon the execution and delivery of this Agreement, this Agreement shall be a legally binding obligation of Lead Market Participant.

10.3.3. Lead Market Participant has, or has applied for, all regulatory authorizations necessary for it to perform its obligations under this Agreement.

10.3.4. The execution, delivery, and performance of this Agreement are within the Lead Market Participant's powers and do not violate any of the terms and conditions in its governing documents, any contracts to which it is a party, or any Law applicable to it.

ARTICLE 11

MISCELLANEOUS PROVISIONS

11.1. Assignment.

11.1.1. None of the Parties shall assign its rights or delegate its duties under this Agreement without the prior written consent of the other Parties, which consent shall not be unreasonably withheld, conditioned, or delayed. Any such assignment or delegation made without such written consent shall be null and void. Upon any assignment made in compliance with this Article 11.1, this Agreement shall inure to and be binding upon the successors and assigns for the assigning Parties.

11.1.2. Notwithstanding Section 11.1.1, each Party may, without the need for consent from the other Parties (and without relieving itself from liability hereunder), transfer or assign this Agreement: (i) to an Affiliate, or (ii) where such transfer is incident to a merger or consolidation with, or transfer of all, or substantially all, of the assets of the transferor to another person, business entity, or political subdivision or public corporation created under the Laws governing the creation and existence of the transferor which shall as a part of such succession assume all of the obligations of the assignor or transferor under this Agreement; provided, however, that any Party who transfers or assigns this Agreement as provided in subsections “i” or “ii” of this Section 11.1.2 shall provide timely notice to the other Party or Parties of such change, including the effective date and changes, if any, to the nominations under Section 11.2 and Exhibits A or B, as appropriate. Any Party may collaterally assign its rights in this Agreement to its lenders without the need for consent from the other Party. To the extent that any Party seeks to transfer its rights and obligations to a successor entity, such Party shall seek to assign this Agreement to such successor entity, pursuant to this Section 11.1.2.

11.1.3. Upon 60 days’ notice from Owner or Lead Market Participant, Lead Market Participant’s function as Lead Market Participant under this Agreement may be assigned to another entity fully capable of fulfilling this role consistent with the ISO New England Filed Documents and the ISO New England System Rules. The Owner, the current Lead

Market Participant and any successor Lead Market Participant must comply with all ISO requirements for Customer Asset registration. Owner is not obligated to assign the Lead Market Participant role to another entity.

11.2. Notices.

Except as otherwise expressly provided in this Agreement or required by Law, all notices, consents, requests, demands, approvals, authorizations and other communications provided for in this Agreement shall be in writing and shall be sent by personal delivery, certified mail, return receipt requested, facsimile transmission, or by recognized overnight courier service, to the intended Party at such Party's address set forth below. All such notices shall be deemed to have been duly given and to have become effective: (a) upon receipt if delivered in person or by facsimile; (b) two days after having been delivered to an air courier for overnight delivery; or (c) seven days after having been deposited in the United States mail as certified or registered mail, return receipt requested, all fees pre-paid, addressed to the applicable addresses set forth below. Each Party's address for notices shall be as follows (subject to change by notice in accordance with the provisions of this Section 11.2):

OWNER AND LEAD MARKET PARTICIPANT:	ISO:
NOTICES & CORRESPONDENCE	NOTICES & CORRESPONDENCE Robert
Ethier Senior Vice President – Wholesale Trading President	Vice
Exelon Generation Company 1310 Point Street, 8th Floor Baltimore, MD 21231 Tel: (410) 470-8115 Fax: (443) 213-3424	ISO New England Inc. One Sullivan Road Holyoke, MA 01040 Tel: (413) 540-4412 Fax: (413) 540-4226

with a copy to:

General Counsel Exelon Generation Company 1310 Point St., 8th Floor Baltimore, MD 21231 Tel: (410) 470-3416 Fax: (443) 213-3556	Maria Gulluni Legal Department ISO New England Inc. One Sullivan Road Holyoke, MA 01040 Tel: (413) 540-4473 Fax: (413) 535-4379

The foregoing notice provisions may be modified by providing written notice, in accordance with ISO Protocols established from time-to-time.

11.3. Parties' Representatives.

All Parties to this Agreement shall ensure that throughout the term of this Agreement, duly appointed representatives are available for communications between the Parties. The representatives shall have full authority to deal with all day-to-day matters arising under this Agreement. Acts and omissions of representatives shall be deemed to be acts and omissions of the Party. Owner, Lead Market Participant and ISO shall be entitled to assume that the representatives of the other Parties are at all times acting within the limits of the authority given by the representatives' Party. Owner's and Lead Market Participant's representatives shall be identified on Exhibit A. ISO's representatives shall be identified on Exhibit B. The Parties may at any time replace their representatives by sending the other Parties a revision to its respective Exhibit.

11.4. Effect of Invalidation, Modification, or Condition.

Each covenant, condition, restriction, and other term of this Agreement is intended to be, and shall be construed as, independent and severable from each other covenant, condition, restriction, and other term. If any covenant, condition, restriction, or other term of this Agreement is held to be invalid or otherwise modified or conditioned by any Governmental Authority, the invalidity, modification, or condition of such covenant, condition, restriction, or other term shall not affect the validity of the remaining covenants, conditions, restrictions, or other terms hereof. If an invalidity, modification, or condition has a material impact on the rights and obligations of the Parties, the Parties shall make a good faith effort to renegotiate and restore the benefits and burdens of this Agreement as they existed prior to the determination of the invalidity, modification, or condition. If the Parties fail to reach agreement, then the Party whose rights and obligations have been adversely affected may, in its sole discretion, terminate this Agreement or refer the dispute for resolution under the Alternative Dispute Resolution provisions in Appendix D of Market Rule 1.

11.5. Amendments.

Any amendments or modifications of this Agreement shall be made only in writing and duly executed by all Parties to this Agreement. Such amendments or modifications shall become effective only after the Parties have received any authorizations required from the Commission. The Parties agree to negotiate in good faith any amendments to this Agreement that are needed to reflect the intent of the Parties as expressed herein, or, following Commission approval of such cost increases, any material increases in the costs of owning and operating the Resources.

11.6. Governing Law.

This Agreement shall be governed by and construed under the Laws of the Commonwealth of Massachusetts without regard to conflicts of laws principles.

11.7. Entire Agreement.

This Agreement consists of the terms and conditions set forth herein, as well as the Appendices hereto, which are incorporated by reference herein and made a part hereof. This Agreement contains the entire agreement between the Parties and supersedes all prior negotiations, undertakings, agreements and business term sheets.

11.8. Independent Contractors.

Owner, Lead Market Participant and ISO acknowledge that as between Owner and/or Lead Market Participant and ISO there is an independent contractor relationship, and that nothing in this Agreement shall create any joint venture, partnership, or principal/agent relationship between the Parties. Neither Owner or Lead Market Participant nor ISO shall have any right, power, or authority to enter into any agreement or commitment, act on behalf of, or otherwise bind the other Party in any way.

11.9. Execution and Counterparts.

This Agreement may be executed in one or more counterparts each of which shall be deemed an original and all of which shall be deemed one and the same agreement. This Agreement shall become effective upon Commission approval and final execution, as set forth in Section 2.1 hereof. Initial execution of this Agreement excludes (in the case of ISO) acceptance of the Annual Fixed Revenue Requirement, Stipulated Variable Costs, and Monthly Fuel Supply Costs.

11.10. Confidentiality.

Confidential information identified as such by a Party and provided to the other Party pursuant to this Agreement shall be governed by the ISO New England Information Policy, subject to the following:

11.10.1. Nothing herein or therein shall limit the right of a Party to file a copy of this Agreement with the Commission, without redaction, to the extent that law, regulation, or agency order makes such filing necessary or appropriate.

11.10.2. Notwithstanding anything in this Agreement to the contrary, if during the course of an investigation or otherwise, the Commission requests that a Party (the "responding Party") provide to it information that has been designated by the other Party to be treated as confidential under this Agreement, the responding Party shall provide the requested information to the Commission or its staff within the time provided for in the request for information. The responding Party shall promptly notify the other Party upon receipt of any such request and either Party, consistent with 18 CFR § 388.112, may, but shall not be required, to request that the information be treated as confidential and non-public by the Commission and its staff and that the information be withheld from public disclosure.

11.11. Submittal to the Commission.

The Parties acknowledge and agree that (i) the Annual Fixed Revenue Requirement and any subsequent changes thereto to the formula for calculating Stipulated Variable Costs shall be established pursuant to an FPA Section 205 proceeding to be initiated by application of Owner; and (ii) this Agreement constitutes the basis for Owner's recovery of its fixed and variable costs for operating and maintaining the Resources during the Term.

ARTICLE 12

REFUND OF CERTAIN CAPITAL EXPENDITURES AND REPAIR EXPENSES

12.1 Refund of Certain Capital Expenditures and Repair Expenses

Subject to the Operational Trigger, in the event one or more Resources or the LNG Terminal remain operational beyond the termination date of the Agreement, Owner and/or Lead Market Participant shall refund to ISO any capital expenditures or repair expenses collected in connection with this Agreement in accordance with the following Refund Amount:

Refund Amount = (A + B) + Interest at the FERC-approved rate

A = actual cost of capital expenditures paid, less depreciation as determined under generally accepted accounting principles

B = (the actual cost of repairs that provide significant benefits beyond the cost-of-service commitment period) * ((Number of months the repairs permit the Resource or LNG Terminal to operate less the number of months the repair was in place during the term of the Agreement) / (Number of months the repairs permit the Resource or LNG Terminal to operate))

Where:

The capital expenditures depreciation schedule is consistent with those covered under the Agreement and the number of months of repairs that permit the Resource or LNG Terminal to operate is determined by the Owner or its Lead Market Participant and verified by an independent entity.

Owner or Lead Market Participant shall make payments to ISO in the amount of one-forty-eighth (1/48th) of the Refund Amount each month for forty-eight (48) months unless (i) in the case of the Resource or Resources, the interconnection rights under the ISO-NE tariff are terminated, or (ii) in the case of the LNG Terminal, it ceases to vaporize gas for any continuous three-month period (each, the “Operational Trigger”).

The months that a Resource or the LNG Terminal continue to operate past the termination date of the Agreement need not be continuous, and the requirement of this Article 12 will continue regardless of ownership of the Resource or LNG Terminal.

No less than three (3) months prior to the end of the Agreement term, the Owner or Lead Market Participant shall file with the Commission the Refund Amount calculation and a list of the capital expenditures and repairs included in the calculation. Owner or Lead Market Participant must include in the filing a list of capital expenditures and repairs made during the term of the Agreement period that it did not include in the refund amount calculation.

[Signature Pages

Schedule 1 and
Schedule 2 omitted]

SCHEDULE 3
SUPPLEMENTAL CAPACITY PAYMENT

For each Obligation Month during the Term, a Supplemental Capacity Payment shall be calculated for the Resource(s) as set forth below.

Section III.13 references are to Market Rule 1, Section III.13 – Forward Capacity Market.

The Annual Fixed Revenue Requirement (AFRR) for the Resources for Capacity Commitment Period 2022/2023 is ~~$218,974,263~~ [to be determined by FERC] and Capacity Commitment Period 2023/2024 is ~~$186,951,485~~ [to be determined by FERC].

The AFRR is the cost-of-service for the Resource, including annual fixed operation and maintenance expense and annual expenses, depreciation, amortization, taxes and return, as accepted by the Commission; provided, however, that, due to the ongoing litigation with the City of Everett, the taxes other than income tax component of the AFRR [to be determined by FERC] ~~($15,500,445.00)~~ shall be updated such that [to be determined by FERC] ~~$15,500,445.00~~ shall be replaced with (i) the amount that is equal to the actual property tax applicable to Mystic for 2022 for Obligation Months within Capacity Commitment Period 2022/2023 and (ii) the amount that is equal to the actual property tax applicable to Mystic for 2023 for Obligation Months within Capacity Commitment Period 2023/2024. The annual fixed operation and maintenance expense is the fixed operating & maintenance expense component of the AFRR.

(Part 1)

Supplemental Capacity Payment = Maximum Monthly Fixed Cost Payment

Less: Winter Fuel Security Penalty for Obligation Month not credited to the Monthly Invoice amount under the FSA, and

Less: Revenue Credits for the Obligation Month

Provided that for any given Capacity Commitment Period the monthly Supplemental Capacity Payments are capped so that the cumulative value of the Supplemental

Capacity Payments minus the Monthly Fuel Supply Cost, plus the Revenue Credits shall not exceed the AFRR (subject to the additional provisions of Part 4 if applicable).

In the event that the Supplemental Capacity Payment would otherwise be less than zero in any Obligation Month, the Supplemental Capacity Payment for that Obligation Month shall be zero and the negative remainder shall roll-forward for crediting in a future Obligation Month.

For the last Obligation Month of the Term, the ISO shall charge the Owner for any unapplied roll-forward amount and shall refund that using the same FERC-determined allocator that is used to fund the Supplemental Capacity Payment.

(Part 2)

Maximum Monthly Fixed Cost Payment = [AFRR / 12] + Monthly Fuel Supply Cost The Monthly Fuel Supply Cost is equal to the ~~Fuel Supply Cost (as defined in the Fuel Supply Agreement between Constellation Mystic, LLC and Constellation LNG, LLC ("FSA")~~Monthly Invoice amount (as provided for in the FSA) for the Obligation Month. ~~For the avoidance of doubt, the Monthly Fuel Supply Cost will reflect the Fixed O& M/Return on Investment Costs, Variable O & M Costs, New Regulatory Costs (if any), the Administrative Services Fee, Pipeline Transportation Agreement Costs, Diversion Costs (credited or debited), Daily Gas Sales Costs (credited or debited), the Third-Party Sales Credit for Demand Charges (credited), and the Actual Fuel Cost Adjustment charged under and defined in the FSA. The Actual Fuel Cost Adjustment allows for the credit or debit of any differences between the fuel cost components of the Stipulated Variable Costs set forth in Section 3.4 and Schedule 1 and the commodity cost of fuel for the Resources in accordance with the terms of the FSA for the Obligation Month.~~

(Part 3)

The purpose of the Revenue Credit is to recognize that the Resource has earned revenues from sources other than this Supplemental Capacity Payment. The Supplemental Capacity Payment is reduced accordingly so that the Resource has a total payment potential during the Capacity Commitment Period equal to its Annual Fixed Revenue Requirement plus Monthly Fuel Supply Costs that are not recovered through Stipulated Variable Costs. The

Supplemental Capacity Payments are reduced by any Winter Fuel Security Penalties and negative Capacity Performance Payments not offset by positive Capacity Performance Payments as addressed in Section 3.6.

Revenue Credit for the Obligation Month =

Capacity Base Payment for the Obligation Month calculated in accordance with Section

~~4.4.2~~4.4 above.

Plus: the absolute value of negative Capacity Performance Payments for the Obligation Month as addressed in Section 3.6 above

Less: positive Capacity Performance Payments credited to Owner/Lead Market Participant as addressed in Section 3.6 above

~~Plus: All other revenues related to the Resource (i.e., all revenues except for revenues from the New England Forward Capacity Market) that are in excess of Stipulated Variable Costs.~~

(Part 4)

If this Agreement terminates other than at the end of a Capacity Commitment Period:

The monthly Supplemental Capacity Payments are capped so that the cumulative value of Supplemental Capacity Payments minus the Monthly Fuel Supply Cost plus Revenue Credits shall not exceed the prorated AFRR.

(Part 5)

While the roll-forward provisions of Part 1 provide that the Supplemental Capacity Payment cannot result in a monthly charge to the Resource because of a Supplemental Capacity Payment that calculates to a negative amount, nothing in this Agreement provides that the sum of all charges and credits for the Resource cannot result in a net amount owed to the ISO for any Obligation/Operating Month.

Attachment B

NESCOE Redline changes to

Fuel Supply Agreement (Exh. MYS-0016)

AMENDED AND RESTATED TRANSACTION CONFIRMATION FOR IMMEDIATE DELIVERY

Constellation
An Exelon Company

Date: July 30, 2018

Transaction Confirmation #:

This Transaction Confirmation is subject to the Base Contract between Seller and Buyer. The terms of this Transaction Confirmation are binding unless disputed in writing within 2 Business Days of receipt ~~s~~ unless otherwise specified in the Base Contract.

SELLER:	**BUYER:**
Constellation LNG, LLC 1310 Point Street, 8th Floor Baltimore, MD 21231 Phone: 410-470-3500 Fax: 443-213-3558	Constellation Mystic Power, LLC 1310 Point Street, 8th Floor Baltimore, MD 21231 Phone: 410-470-3500 Fax: 443-213-3558
Base Contract No. ____________________ Transporter: ____________________ Transporter Contract Number: ____________	Base Contract No. ____________________ Transporter: ____________________ Transporter Contract Number: ____________

Condition Precedent: Commencement of service under this Transaction Confirmation is expressly subject to ExGen, or one of its Affiliates, acquiring and owning the LNG Terminal as of the commencement of the Delivery Period, as defined below.

Performance Obligation: Firm, No-Notice Service.

Quantity: Full requirements of Gas for Buyer's Mystic Plant; provided, however, in no event shall Seller be required to deliver Gas in excess of Seller's Firm Weekly Requirement or in excess of 280,000 MMBtu on any Day.

~~**Delivery Period:** June 1, 2022 - May 31, 2024 ("Initial Delivery Period"); provided, however, this Confirmation shall automatically renew beyond the initial term for any period in which a Reliability-Must-Run Contract (or its equivalent) is in effect for the Mystic Plant ("Extended Delivery Period")(the Initial Delivery Period and the Extended Delivery Period, if any, shall be referred to collectively as the "Delivery Period").~~

Delivery Period: June 1, 2022 - May 31, 2024 ("Delivery Period").

Scheduling:

On or before March 1, 2022 and each March 1 thereafter during the Delivery Period, Buyer shall provide to Seller its Annual Delivery Program and Buyer's best available forecast of Buyer's annual requirements of Gas. Buyer shall provide Gas volume identified by Month for the April through October period and by Week for the November through March period.

On or before the tenth (10th) day of each Month, Buyer shall provide to Seller its Ninety Day Schedule, Buyer's best available forecast of Buyer's Gas requirements for the upcoming three month period starting on the first day of the following month, with such Gas volume identified by Week.

On or before the Monday prior to the start of a Week, Buyer shall provide to Seller its best estimate of the Firm Weekly Requirement. The Firm Weekly Requirementshall follow as closely as practicable the applicable Ninety Day Schedule for that same Week.

No later than 7 a.m. Eastern Prevailing Time on the Day prior to the Day of delivery (Day 0), Buyer shall provide to Seller a forecast of the quantity of Gas that Buyer elects to have delivered to the Delivery Point for the next Day (day 1). Should Buyer subsequently request additional volumes, Seller shall promptly confirm the scheduling of such additional volumes and deliver such additional volumes to Buyer.

In any Week, Seller has the option, if requested by Buyer but has no obligation, to provide Gas in excess of Buyer's Firm Weekly Requirement.

Delivery Point: The custody transfer meter at the high-pressure pipeline interconnection between the LNG Terminal and the Mystic Plant.

Contract Price: The ~~price per MMBtu for Gas delivered by Seller to Buyer during the Delivery Period shall be Daily WACOG Price for the Day of delivery~~Contract Price shall consist of a monthly Demand Charge, Commodity Charge, and Reliability Charge.

~~**Gas Supply Costs/Fees:** In addition to the Contract Price, each Month during the Delivery Period Buyer shall pay to Seller the following costs and fees associated with Seller's provision of Firm, No-Notice Service to Buyer:~~

Demand Charge for the Month shall be calculated as follows:

a) 39.16% times sum of i) the Fixed O&M/Return on Investment Costs, ii) New Regulatory Costs, and iii) Administrative Services Fee plus

b) Proportionate Percentage times the sum of i) Variable O&M Costs and ii) Credit and Collateral Cost.

Where: ***Fixed O & M/Return on Investment Costs***~~. Each Month during the Initial~~ for the Delivery Period ~~Buyer shall pay to Seller the following charge for the costs of regassification~~

~~service from the LNG Terminal, which is paid by Seller to DOMAC pursuant to the LNG Terminal Services Agreement:~~shall be,

For Months in Contract Year 2022: $~~7,328,074.00~~/month [TBD by FERC]

For Months in Contract Year 2023: $~~6,856,381.00~~/month [TBD by FERC]

For Months in Contract Year 2024: $~~6,658,432.00~~/month [TBD by FERC]

~~The Fixed O & M/Return on Investment Costs for any Extended Delivery Period shall be established and approved by the applicable Governmental Authority prior to the commencement of such Extended Delivery Period.~~

~~***Variable O&M Costs.*** Each Month Buyer shall reimburse and pay to Seller (i) the variable operating costs of the LNG Terminal paid by Seller to DOMAC for the applicable Month pursuant to the LNG Terminal Services Agreements (ii) the actual costs associated with the performance of Marine Services for the applicable Month, and (iii) the actual Port Use Costs for the applicable Month.~~

New Regulatory Costs. If and to the extent that Seller is required to pay ~~DOMAC any New Regulatory Costs~~any new Rregulatory costs associated with a change in law that is required for Seller to meet its Performance Obligation under this Agreement that are otherwise not collected by DOMAC from Seller under the LNG Terminal Services Agreement~~,~~. Seller shall pass through those costs to Buyer and Buyer shall ~~pay~~reimburse those costs to Seller~~ as they become due.~~, payable as practicable as possible, divided on an even monthly basis for the remaining term of the Delivery Period. Seller and DOMAC shall both use reasonable efforts to minimize the impact of any anticipated New Regulatory Costs.

Administrative Services Fee. ~~Each Month during the Initial Delivery Period Buyer shall pay to Seller~~ $127,750.00 per Month, which is the Administrative Services Fee paid by Seller to ExGen for the applicable Month pursuant to the Intercompany Services Agreement. ~~Payment amounts for the Administrative Services Fee for any Extended Delivery Period shall be established and approved by the applicable Governmental Authority prior to the commencement of such Extended Delivery Period.~~

Proportionate Percentage. For any Month, the volume of natural gas delivered by Seller to Buyer in the Month divided by the total volume of natural gas and LNG delivered by Seller to all customers, including Buyer, in the Month.

Variable O&M Costs shall be the sum of (i) the variable operating costs of the LNG Terminal paid by Seller to DOMAC for the prior Month pursuant to the LNG Terminal Services Agreements, (ii) the actual costs associated with the performance of Marine Services to the extent those actual costs are not duplicative to those costs included in the calculation of the Fixed O&M/Return on Investment Costs, for the prior Month, and (iii) the actual Port Use Costs incurred directly by Seller, if any, for the prior Month. For the first Month following the Delivery Period, Buyer shall make a final payment of actual costs associated with the final Month in the Delivery Period.

Credit and Collateral Costs. Each Month Buyer shall reimburse and pay to Seller the actual credit and collateral costs associated with purchases of LNG to serve Buyer~~ and Third-Party Customers~~, which are the costs Seller pays ExGen for the applicable Month pursuant to the Intercompany Services Agreement. The credit and collateral support costs in the Intercompany Services Agreement are based on the actual costs of (i) ExGen's credit revolver (for letters of credit), and (ii) either the rate of return ExGen could have earned on existing short-term investment accounts or the cost of outstanding commercial paper and/or Exelon money pool balances if ExGen is in a borrowed position, as applicable (for cash utilization), to support Seller.

Commodity Charge. The Commodity Charge shall be calculated daily and will equal the Daily WACOG Price times Gas delivered by Seller to Buyer.

Reliability Charge for the Month will be one-twelfth of the Annual Reliability Charge.

The Annual Reliability Charge will be calculated on or before May 1 of each Contract Year during the Delivery Period. The Annual Reliability Charge will be determined using a FERC-approved Reliability Model as described in Schedule A.

Buyer and/or Buyer's representative as well as a representative of a relevant Governmental Authority shall have the right to review all data and assumptions as updated each year for use in the Reliability Charge Model.

~~***Pipeline Transportation Agreement Costs.*** Each Month Buyer shall reimburse and pay to Seller the demand and commodity charges associated with any pipeline transportation agreements held by Seller or DOMAC pursuant to which Seller or DOMAC transports and sells Gas from the LNG Terminal to Third-Party Customers.~~

~~***Diversion Costs.*** In the event Seller incurs any net fees associated with the diversion of one or more LNG cargo ships scheduled to deliver LNG to the LNG Terminal during a Month, Buyer shall reimburse and pay to Seller any such net fees relating to the diversion. In the event Seller incurs a net benefit associated with the diversion of one or more LNG cargo ships scheduled to deliver LNG to the LNG Terminal during a Month, Seller shall credit such amount to Buyer's invoice for such Month.~~

~~***Daily Gas Sales.*** Each Day during the Delivery Period, Seller shall calculate for each sale of Gas and/or LNG to Third-Party Customers the difference between the Contract Price for each such transaction and the applicable Daily WACOG Price pursuant to the following formula:~~

~~[Contract Price - Daily WACOG Price] x Third-Party Sales Quantity~~

~~Where:~~

~~***Contract Price*** shall mean the contract price per MMBtu for the applicable Third-Party Customer transaction.~~

~~***Daily WACOG Price*** shall mean the Daily WACOG Price for the applicable Day~~

~~***Third-Party Sales Quantity*** shall mean the Quantity of LNG or Gas sold and delivered to the Third-Party Customer in the applicable Day under the applicable transaction on a MMBtu basis.~~

~~If the result of such calculation is positive, such amount shall be a credit to Buyer's Fixed O&M Costs for such Month. If the result of such calculation is negative, such amount shall be a debit to Buyer's Fixed O&M Costs for such Month. Each Month, Seller shall net and offset all such calculations for such Month and credit or debit such net amount to Buyer's Fixed O&M Costs for such Month.~~

~~**Third-Party Sales Credit for Demand Charges:**~~

~~During any period for which a Reliability-Must-Run Contract (or its equivalent) is in effect for the Mystic Plant:~~

~~(i) For each Gas or LNG sales transaction between Seller and a Third-Party Customer entered into less than three (3) Months in advance of the commencement date of the Delivery Period of such transaction, Seller shall credit to Buyer the entire Demand Charge associated with such transaction (if any).~~

~~(ii) Customer entered into three (3) or more Months in advance of the commencement date of the Delivery Period of such transaction (a "Forward Transaction"), Seller shall credit to Buyer the Demand Charge associated with such Forward Transaction (if any), less Seller's Incentive.~~

~~Where:~~

~~**Seller's Incentive = Forward Sale Margin multiplied by 50%**~~

~~Where:~~

~~**Forward Sale Margin =**~~

~~**Contract Revenue - Contract Incremental Cost - Tank Congestion Charge**~~

~~Where:~~

~~**Contract Revenue** = the sum of fixed payments due from the Third-Party Customer under such Forward Transaction during a given Capacity Commitment Period~~

~~**Contract Incremental Cost** = the anticipated total variable cost to be incurred by Seller in accepting an LNG cargo delivered to the LNG Terminal during such Capacity~~

~~Commitment Period, multiplied by the maximum quantity of Gas (in BCF) or LNG (in BCF equivalent) to be delivered under such Forward Transaction during such Capacity Commitment Period, divided by 3 BCF~~

~~**Tank Congestion Charge** = the cost, if any, associated with (i) the increased need for uneconomic self-scheduling at the Mystic Plant or (ii) short-term vaporization LNG from the LNG Terminal with a negative margin, that is attributable to such Forward Transaction.~~ No later than six (6) months prior to the commencement of performance under any Reliability-Must-Run Contract in effect for the Mystic Plant, the ISO shall approve the final methodology ~~of~~for calculating ~~a Tank Congestion~~the Reliability Charge; provided, that the conceptual outline of such methodology is set forth in Schedule A.

~~(iii) If the applicable transaction is a Forward Sale Transaction, Seller's incentive shall be deducted ratably from the fixed payments due from the Third-Party Customer under such Forward Sale Transaction during such Capacity Commitment Period; if the applicable transaction is a Forward Option Transaction, Option Payment will be credited (net of Seller's margin) pro rata over the delivery months of LNG or Gas deliveries set forth in such transaction during such Capacity Commitment Period.~~

~~(iv) Seller's Incentive shall be calculated at the time of contract execution for the related Forward Transaction. There shall be no subsequent adjustment to such Seller's Incentive calculation based on actual deliveries of Gas or LNG thereunder. Notwithstanding the preceding provisions of this subsection (iii), in the event of Seller's non-performance of a Forward Transaction for which a Seller's Incentive amount has been calculated and which results in a reduction of the fixed payments received by Seller thereunder, the amount of the Seller's Incentive shall be reduced by the product of (a) the reduction of the fixed payment, multiplied by (b) 50%.~~

~~(v) Seller shall not be entitled to reduce the credit due to Buyer pursuant to subsection (ii) due to (a) Seller's payment of any cover costs associated with Seller's nonperformance of a Forward Transaction or (b) the failure by a Third-Party Customer to pay amounts owed to Seller under a Forward Transaction.~~

~~(vi) For the avoidance of doubt, a Seller's Incentive amount shall only be applied in periods in which a fixed payment under a Forward Sale Transaction has been received by Seller from the related Third-Party customer. In the case of a Forward Option Payment, a Seller's Incentive amount shall only be applied in periods in which LNG or Gas is delivered to and payment made by the related Third-Party Customer.~~

~~(vii) Seller shall be precluded from entering into any Forward Transaction in which the contract price per MMBtu for the applicable Forward Transaction is less than Seller's cost of LNG supply (on an MMBtu basis) for the contract delivery period at the time of execution of such Forward Transaction.~~

~~(viii) In the event that Seller's credit to Buyer under subsection (ii) above in any Month exceeds Buyer's net payment to Seller for such Month, the difference between~~

~~such credit mount and Buyer's invoice amount for such Month shall be carried forward and setoff against Buyer's invoice amount for the following Month. If a credit to Buyer still exists at the end of any Reliability-Must-Run Contract, Seller shall promptly pay such amount to Buyer.~~

Monthly Invoice: Seller shall invoice Buyer for Gas delivered and received in the preceding Month and for any other applicable charges set forth herein. Such invoice shall contain the following line items:

~~1. Commodity Cost (the sum of the Daily WACOG x Daily Quantity Delivered)~~

1. **Demand Charge** showing a breakdown of all components comprising the Demand Charge;
2. **Commodity Charge** showing daily volumes and prices;
3. **Reliability Charge** (one-twelfth of Annual Reliability Charge);
4. Less:
   a. The sum of Winter Fuel Security Penalties incurred by Buyer under the COSA for the Month as a direct result of Seller's failure to meet its obligation under the Base Contract or FSA for the Month; and
   b. The sum of Capacity Performance Payments incurred by Buyer under the COSA as a direct result of Seller's failure to meet its obligation under the Base Contract or FSA for the Month; and
   c. The sum of Fuel Supplier Self Scheduling Losses for the Month; and
   d. The sum of Opportunity Cost Losses for that Month.

~~2. Fuel Supply Cost~~

~~a. Fixed O & M/Return on Investment Costs~~
~~b. Variable O & M Costs~~
~~c. New Regulatory Costs (if any)~~
~~d. Administrative Services Fee~~
~~e. Credit and Collateral Costs~~
~~f. Pipeline Transportation Agreement Costs~~
~~g. Diversion Costs (credit or debit)~~
~~h. Daily Gas Sales Costs (credit or debit)~~
~~i. Third-Party Sales Credit for Demand Charges (credit)~~
~~j. Actual Fuel Cost Adjustment (as defined below)~~

~~**Actual Fuel Cost Adjustment:** To the extent that Buyer's actual fuel costs in item #1 differ from sum of the "Fuel Index Price" and/or the "Fuel Variable/Other Cost" components of its "Stipulated Variable Costs" approved by the ISO IMM, and such difference precludes Buyer from recovering its actual fuel costs because of the operation of the Revenue Crediting mechanism contained in any Reliability-Must-Run Contract (or its equivalent), the difference between Buyer's actual fuel costs for such Month (item #1) and the amount Buyer is permitted to recover for fuel in its Stipulated Variable Costs for such Month shall be added as a separate line item (j) in the following Month's invoice and Buyer shall pay to Seller such costs. To the extent that Buyer's actual fuel costs in item #1 differ from sum of the "Fuel Index Price" and/or the "Fuel Variable/Other Cost" components of its "Stipulated Variable Costs" approved by the ISO IMM, and such difference will result in Buyer recovering more than its actual fuel costs as a~~

~~result, the difference between the sum of the "Fuel Index Price and/or the "Fuel Variable/Other Cost" and Buyer's actual fuel costs for such Month (item #1) shall be subtracted as a separate line item (j) in the following Month's invoice and Buyer shall pay to Seller such costs.~~

~~**Nominations:** No later than 2 p.m. Eastern Prevailing Time on the Day prior to the Day of delivery (day 0), Buyer shall provide to Seller a non-binding forecast of the quantity of Gas that Buyer elects to have delivered to the Delivery Point for the next Day (day 1). Should Buyer subsequently request additional volumes, Seller shall promptly confirm the scheduling of such additional volumes and deliver such additional volumes to Buyer.~~

Force Majeure: For the purposes of this Transaction Confirmation, Section 11.2 in the Base Contract shall be deleted and the following inserted in lieu thereof:

> "Force Majeure shall include, but not be limited to acts of God; fires; floods; storms or storm warnings; hurricanes; riots; insurrections; acts of war (whether declared or otherwise); blockades; acts of the public enemy; epidemics; landslides; lightning; washouts; arrests and restraints of governments and peoples; acts of a Government Authority (such as necessity for compliance with any court order, law, statute, ordinance, regulation, or policy having the effect of law promulgated by a governmental authority having jurisdiction); labor strikes, lock-outs, and similar organized labor actions involving a substantial portion of the affected Party's workforce; explosions, breakage, or accident to machinery, lines of pipe, terminalling facilities or electric generating facilities (including both turbine and non-turbine equipment); malfunctioning (or non-functioning) of turbine or non-turbine equipment at the Mystic Plant which renders such facilities wholly or partly unable to operate; the necessity of making repairs or required alterations to machinery, lines of pipe, terminalling facilities or electric generating facilities (but not including any scheduled maintenance); unplanned outages at the LNG Terminal; unplanned outages at the Mystic Plant; an event qualifying as Force Majeure hereunder which prevents or impedes performance on the part of a Third-Party transporting or delivering Gas or LNG to or on behalf of Seller; or any other causes, whether of the kind enumerated herein or otherwise, beyond the reasonable control of and without the fault, negligence, or willful misconduct of the Party claiming Force Majeure. The term Force Majeure shall apply equally to events preventing or impeding the operations of the LNG Terminal, the Mystic Plant, any interstate pipeline or other gas transporter which is required to receive, transport or deliver Gas to be sold or purchased hereunder, any LNG carrier transporting LNG to be terminalled by Seller at the LNG Terminal and resold as Gas to Buyer, any LNG supplier furnishing LNG to be terminalled by Seller at the LNG Terminal and resold as Gas to

Buyer, or any transmitter of electric energy from the Mystic Plant. For purposes of this definition, a "Third-Party" shall be deemed to include any Affiliate of Buyer or Seller. Seller and Buyer shall make reasonable efforts to avoid the adverse impacts of a Force Majeure and to resolve the event or occurrence once it has occurred in order to resume performance."

Definitions: Capitalized terms not defined herein shall have the meaning ascribed to them in the Base Contract.

~~**"Capacity Commitment Period"** is the one-year period from June 1 through May 31 for which obligations are assumed and payments are made in the Forward Capacity Market.~~

"Annual Delivery Program" is the forecast provided by Buyer to Seller regarding Buyer's annual vaporized LNG requirements.

"Capacity Performance Payments" shall have the same meaning as provided for in COSA Section 3.6.

"Contract Year" shall mean each period of twelve (12) consecutive months commencing on ~~January~~June 1st and ending on the following ~~December~~May 31st~~; provided that the first Contract Year shall begin on June 1st and the~~. The last Contract Year shall terminate as of such expiration or termination date of any Reliability-Must-Run Agreement (or equivalent).

"Cost of Service Agreement" or "COSA" shall mean the agreement dated May 15, 2018 between (i) Buyer and Buyer's affiliate Exelon Generation Company, LLC and (ii) ISO New England Inc., subject to FERC approval in Docket No. ER18-1639-000.

"Daily WACOG Price" shall mean the weighted average cost of all LNG (on ~~a~~an MMBtu basis) in the storage ~~tank~~tanks located at the LNG Terminal on the applicable Day of delivery.

"Day" shall mean a calendar day.

~~**"Demand Charge"** shall mean a reservation fee or an option fee that a Third-Party Customer pays to Seller for the right to purchase and receive Gas and/or LNG from Seller via the LNG Terminal over an established period of time, where such costs are to be incurred whether the service is used or not.~~

"DOMAC" shall mean Distrigas of Massachusetts LLC and its successors.

"ExGen" shall mean Exelon Generation Company, LLC and its successors.

"FERC" shall mean the U.S. Federal Energy Regulatory Commission or any successor agency.

"**~~Forward Option Transaction~~Firm Weekly Requirement**" shall mean ~~any Forward Transaction in which the Third-Party Customer is granted a purchase option for~~Buyer's best estimate of Gas ~~or LNG~~for the Week.

"Fuel Opportunity Cost" shall have the same meaning as provided for in Section 3.4.1.4 of the COSA.

"Fuel Supplier Self Scheduling Loss" shall have the same meaning as provided for in Section 3.5 of the COSA.

"**~~Forward Sale Transaction~~Gas**" shall mean ~~any Forward Transaction in which the Third-Party Customer is not granted a purchase option for Gas or LNG~~a merchantable mixture of methane and other gaseous hydrocarbons that complies with all applicable industry specifications.

"**Government Approvals**" ~~-~~ shall mean all certificates, permits, licenses, approvals and authorizations from any Governmental Authority necessary to effectuate the transactions contemplated by this Agreement.

"**Governmental Authority**" ~~-~~ shall mean any federal, state or local governmental agency or other authority in the United States of America or other country having jurisdiction over any aspect of the activities and transactions contemplated by this Agreement, including but not limited to FERC, ISO, and ISO IMM.

"**Governmental Authorizations**" shall mean all permits, authorizations, variances, approvals, registrations, certificates of legal status, certificates of occupancy, orders or other approvals or licenses (and in any case, any amendments or supplements thereto) granted or issued by any Governmental Authority having or asserting jurisdiction over matters covered by this Agreement.

"**Intercompany Services Agreement**" shall mean that certain Services Agreement by and between Seller and ExGen executed contemporaneously herewith pursuant to which ExGen provides Seller certain management, administrative and other services described in the agreement.

"**ISO**" shall mean ISO New England, and any successor thereto.

"**ISO IMM**" shall mean the internal market monitoring unit of ISO.

"**LNG**" shall mean ~~Natural~~ Gas in a liquid state at a temperature that is at or below its point of boiling and at or near atmospheric pressure.

"**LNG Tanker**" shall mean an ocean-going vessel being used or that will be used by or for the benefit of Seller to unload LNG at the LNG Terminal for Seller's account-including all vessels owned, operated, leased or chartered by Seller or by any Person for whom DOMAC unloads LNG on behalf of Seller.

"**LNG Tanker Charges**'' shall mean all charges (including rates, tolls, fees, taxes or dues of any description) due to Persons other than DOMAC for an LNG Tanker entering or leaving the LNG Terminal or Boston Harbor, including all port and channel usage and maintenance charges, all charges imposed by the providers of Marine Services, the United States Coast Guard. Pilots, and any other Person assisting an LNG Tanker to enter or depart the LNG Terminal or Boston Harbor, including any costs associated with security of the LNG Tankers while entering or departing Boston Harbor or while at the LNG Terminal.

"**LNG Terminal**" shall mean the facilities owned and operated by Seller's affiliate, Distrigas of Massachusetts LLC or its successor, that are located in Everett, Massachusetts, which are related to receiving LNG, storing and delivering LNG, vaporizing LNG, and delivering ~~Vaporized~~vaporized LNG to Buyer, and vaporized LNG and LNG to Third-Party Customers.

"**LNG Terminal Services Agreement**" shall mean that certain LNG Terminal Services Agreement by and between Seller and DOMAC executed contemporaneously herewith.

"**Management Services Fee**" shall mean the monthly fee paid by Seller to ExGen for services rendered under the Intercompany Services Agreement.

"**Marine Services**" shall mean Tug Services, other service boats, pilots, fire boats, escort vessels, and harbor, port. LNG Tanker mooring or other support services required during arrival or unloading of LNG Tankers, or for the operations, transiting, berthing, shifting berths, or departure of LNG Tankers, including such vessels or services as may be required under applicable law or regulations of Governmental Authorities having jurisdiction over the LNG Terminal.

~~"**Master**'' shall mean, with respect to an LNG Tanker, the duh licensed master, captain or other person lawfully in command of such LNG Tanker.~~

"**Month**" shall mean a calendar month commencing at 00:00:01 hours Eastern Prevailing Time on the first day of such month and ending at 00:00:00 hours Eastern Prevailing Time of the last day of such month.

"**Mystic Plant**" shall mean natural gas-fired, combined cycle electric power generation facility owned and operated by Buyer located in Everett, Massachusetts.

~~"**New Regulatory Costs**" shall mean those costs paid by Seller to DOMAC pursuant to the LNG Terminal Services Agreement resulting from, among other things, new requirements (or changes to existing requirements) imposed on the LNG Terminal or DOMAC by any Governmental Authority which requires DOMAC to incur any material cost in excess of the costs which would have been incurred by DOMAC absent such change in law.~~

"Ninety Day Schedule" is the forecast provided by Buyer to Seller regarding Buyer's vaporized LNG requirements for the three (3)-month period commencing on the first (1st) Day of the Month following issuance of such forward plan that follows as closely as practicable the applicable Annual Delivery Program for that same three (3)-month period.

"Opportunity Cost Losses" shall mean the lost energy market margins incurred by Buyer, if any, resulting from Seller's request to increase the Fuel Index by a Fuel Opportunity Cost; in each instance is equal to the additional energy sale quantity that was offered and would have occurred had the Stipulated Variable Cost not included Fuel Opportunity Cost, times the difference between the energy price that would have been earned, had the Stipulated Variable Cost not included Fuel Opportunity Cost, and the Stipulated Variable Cost without Fuel Opportunity Cost.

"Person" shall mean any individual, firm, corporation, trust, partnership, limited liability company, association, joint venture, other business enterprise or any Governmental Authority.

"Pilot" shall mean any person, duly licensed and authorized by the State of Massachusetts to act as a Boston Harbor pilot of an LNG Tanker, requested by DOMAC. Seller or required by a Governmental Authority to come onboard an LNG Tanker to assist the Master in the safe navigation, transit, maneuvering, arrival, berthing, deberthing, shifting berths, or departure of such LNG Tanker.

"Port Use Costs" are any and all LNG Tanker Charges, and charges associated with obtaining and maintaining (or causing to be obtained and maintained) all Governmental Authorizations in connection with Seller's use of, or movements by, the LNG Tankers, including port licenses, marine and other environmental permits and other technical and operational authorizations from all Governmental Authorities.

"Reliability Charge Model" is the FERC-approved model that calculates the Annual Reliability Charge associated with the deliveries of a reliable supply of Gas by Seller to Buyer for the Contract Year.

"Self-Scheduling Losses" shall mean the negative energy market margins that occur when Fuel Supplier requests dispatch of Mystic when it would not otherwise operate based on Stipulated Variable Cost, and in each instance is equal to the additional energy sale quantity that occurred due to the Fuel Supplier request to self-schedule, times the difference between the Stipulated Variable Cost and the (lower) energy price that was earned.

"Stipulated Variable Cost" shall have the same meaning as provided for in Section 3.4.1 of the COSA.

"Week" shall mean the period beginning 9 a.m. Central Prevailing Time each Monday and ending at 9 a.m. Central Prevailing Time the following Monday.

"Winter Fuel Security Penalty" shall have the same meaning as provided for in Section 3.7 of the COSA.

"Week" shall mean the period beginning at 9:00 a.m. Central Prevailing Time each Monday and ending at 9:00 a.m. Central Prevailing Time the following Monday.

~~**“Third-Party Customers”** shall mean those customers other than Buyer or its successors purchasing and receiving LNG and/or Gas from Seller via the LNG Terminal.~~

~~**“Tug Services”** shall mean such tugs and services (including escort, berthing, de-berthing, shifting berths, towage and other tug services) as contracted by Seller with tug service providers.~~

Seller: **Constellation LNG, LLC**	Buyer: **Constellation Mystic Power, LLC**
By:	By:
Title:	Title:
Date:	Date:

Schedule A: Reliability Charge Model

~~In connection with the incentive provision in this Transaction Confirmation, Seller, Buyer and ISO New England have agreed that the calculation of the incremental cost of third party forward sales from the LNG Terminal should include an ex ante estimate of any increase in "tank congestion costs" that are attributable to such third part sales. Tank congestion costs can arise from "forced" sales of Gas to either Buyer for the Mystic Plant or Third-Party Customers that are necessary to make room in the tank for an incoming cargo. As contracted volume from the tank increases, and ship frequency increases, the magnitude of such forced sales also increases.~~

The Annual Reliability Charge for each Contract Year will be calculated on or before May 1 of each Contract Year during the Delivery Period. The Annual Reliability Charge shall be calculated on an *ex ante* basis using a FERC-approved Reliability Charge Model.

The Reliability Charge Model assumptions will be updated each year as agreed by Buyer, Seller, and ISO. Buyer and/or Buyer's representative as well as a representative of a relevant Governmental Authority shall have the right to review all data and assumptions as updated each year for use in the Reliability Charge Model.

The Reliability Charge Model will then be used to determine the LNG cargo schedule that results in the minimum Annual Reliability Charge. The Annual Reliability Charge will be set to this minimum value. Seller shall act as a reasonable and prudent operator in its scheduling of LNG cargoes and operation of the LNG Terminal, however, Seller is not required to follow the cargo delivery schedule that is assumed in the Reliability Charge Model for setting the Annual Reliability Charge.

Seller, Buyer and the ISO have agreed on a conceptual methodology to estimate the various costs Seller would incur, in addition to fixed costs and commodity costs, to provide the required service to Buyer, which costs should be reflected in the Annual Reliability Charge. The Reliability Charge Model shall simulate factors including but not limited to (i) deliveries of LNG cargoes to Everett, (ii) simulated design weather patterns for the Contract Year, (iii) simulated daily natural gas prices based on futures prices for Algonquin Citygates or a similar index, the Dutch Title Transfer Facility or a similar world LNG price index, and the design weather patterns; (iv) simulated Buyer demands based on the simulated weather and price patterns; (v) operation of Everett to manage tank levels, which may involve forced sales onto the pipelines, requests for self-scheduling of Mystic, or requests for Mystic dispatch based on a price in excess of WACOG.

~~Seller, Buyer and ISO New England have agreed on a conceptual methodology to estimate the increase in tank congestion costs utilizing~~The approach will utilize a monte carlo simulation of winter dispatch from the LNG Terminal under a "Mystic Plant sales only" ~~base case compared to a "Mystic Plant plus third party sales" change case with equivalent delivery reliability. The change in forced sales and the associated change in forced sale margin between the base case and the change case will be used to calculate the tank congestion costs term in the Forward Sale Margin formula~~scenario. The monte carlo simulation model will generate hundreds of individual scenarios of daily average temperature in Boston based on decades of daily winter temperature history. For each of these daily temperature scenarios, the model will determine the economic dispatch from the LNG Terminal based on a relationship between average temperature and AGT daily prices. The tank dispatch will honor the physical constraints of the tank and downstream delivery systems, and the need to have room in the tank to accept scheduled deliveries. In each scenario, the level of forced sales will be calculated together with the associated margin, and aggregated to an expected level of margin from forced sales. This expected value will be ~~used for the tank congestion costs calculation.~~ reflected in the Annual Reliability Charge calculation. The Annual Reliability Charge calculation will also reflect simulated values for Winter Fuel Security Penalties when due to fuel shortage; Capacity Performance Payments when due to fuel shortage; and Buyer lost margins due to Seller requested dispatch using an opportunity cost.

~~As an example of this approach, consider a forward sale of a winter daily option of 100,000 mcf/day. Assume that the expected margin associated with forced sales between the Mystic-only case and the Mystic plus 200,000 mcf/day daily options decreased by $20 million over the winter. In that circumstance, the tank congestion costs applicable to the Forward Sale Margin calculation for the 100,000 mcf/day sale would be half of $20 million, or $10 million.~~

Attachment C

NESCOE Mark-Up of Schedule 3A (Exh. MYS-0052)

SCHEDULE 3A
RESOURCE COMPENSATION TRUE-UP

I. Projected Cost Update, Capital Expense Support, and True-Up

The projections of certain components of the Annual Fixed Revenue Requirement and the Monthly Fuel Supply Cost as detailed below will be updated prior to the Term and are subject to true-up under the methodology outlined in Section III~~.~~ ("Methodology"). The estimate or forecast identified in the "Mystic 8&9 True-Up" and "EMT True-Up" tabs provided in the Methodology will be updated prior to the Term and are subject to a true-up adjustment to the actual costs incurred by Owner for maintaining and operating the Resources for the components of cost specified below.

Capital expenditures that will be incurred during the Term will be supported prior to their incurrence and are subject to a true-up adjustment to the actual costs in accordance with the protocols as detailed below and the Methodology.

Actual costs may be larger or smaller than estimated or forecast costs, so the true-up adjustment may be made in either a positive or negative direction~~.~~, subject to the following limitations ("True-up Limitations"):

1. Cash Working Capital shall be set at $0 for both Resource and LNG Terminal for purposes of true-up of the return;
2. Overtime Labor Expenses. The true-up adjustment relative to Overtime Labor Expenses shall not exceed 21% of base pay for either Resource or LNG Terminal employees;
3. Incentive Pay. The true-up adjustment relative to Incentive Pay shall not exceed 13.3% of base pay for either Resource or LNG Terminal employees and shall not include incentive pay based on the financial performance of Owner or its affiliates; and
4. Total Operations and Maintenance Expenses. The true-up adjustment relative to Total

Operations and Maintenance shall not exceed 2% of projected amounts on an annual basis.

A. Costs and Formula Rate Inputs Subject to Updated Projection and True-Up

The Annual Fixed Revenue Requirement, the Maximum Monthly Fixed Cost Payment, and the Fixed O & M/Return on Investment component of the Monthly Fuel Cost Charge set forth in Schedule 3 of the Agreement shall be updated prior to the Term and subject to true-up as detailed herein and in accordance with the Methodology for ~~the following cost and only the following components: 1) capital expenditures~~1) all components of rate base, including excess deferred income taxes;~~-~~ 2) operations and maintenance expenses~~ and one eighth O&M cash working capital allowance~~; 3) administrative and general expenses; ~~and~~ 4) taxes other than income

taxes; and 5) federal income taxes.

B. Administrative Filings

On or before April 1st of each year prior to the first True-Up Filings, beginning with April 1, 2019, Owner shall file an Administrative Filing that details the capital expenditures for the Resources and the LNG Terminal for the previous calendar year. In connection with the True-Up Filings detailed in Section I.C, Interested Parties may use information and data provided in an Administrative Filing and responses to interrogatory requests as part of the Information Exchange and Challenge Procedures detailed in Section II.

1. 2019 Administrative Filing:

i. Update to Net Plant for Capital Expenditures in 2018

On or before April 1, 2019, Owner shall file an Administrative Filing that details capital expenditures incurred during calendar year 2018. The Administrative Filing will include net plant updated to include actual capital expenditures and depreciation incurred between January 1, 2018 and December 31, 2018. Interested Parties shall have to right to submit no more than twenty (20) interrogatories related specifically to the capital expenditures. Owner shall respond to these interrogatories within fifteen (15) calendar days. For projected capital projects for the next calendar year, Owner will provide a description of the project(s), the need for the project(s), the alternatives considered with respect to the least-cost alternatives, the expected start and completion date(s), and the project costs.

2. 2020 Administrative Filing:

i. Update to Net Plant for Capital Expenditures in 2019

On or before April 1, 2020, Owner shall file an Administrative Filing that details capital expenditures incurred during calendar year 2019. The Administrative Filing will include net plant updated to include actual capital expenditures and depreciation incurred between January 1, 2018 and December 31, 2019. Interested Parties shall have to right to submit no more than twenty (20) interrogatories related specifically to the capital expenditures. Owner shall respond to these interrogatories within fifteen (15) calendar days. For projected capital projects for the next calendar year, Owner will provide a description of the project(s), the need for the project(s), the alternatives considered with respect to the least-cost alternatives, the expected start and completion date(s), and the project costs.

C. True-Up Filings

Each of the ~~filings~~True-Up Filings detailed below (collectively "Filings") are subject to and will be made in accordance with the Information Exchange and Challenge Procedures detailed in Section II, including any capital expenditures incurred prior to the Term (i.e., between January 1, 2018 and May 31, 2022). Each of the Filings may increase or decrease the Annual Fixed Revenue Requirement, the Maximum Monthly Fixed Cost Payment, and the Fixed O & M/Return on Investment component of the Monthly Fuel Cost Charge so each adjustment may be made in either a positive or negative direction. In connection with the Filings, Interested Parties may use information and data provided in an Administrative Filing and responses to interrogatory requests as part of the Information Exchange and Challenge Procedures detailed in Section II.

1. 2021 Filing:

i. Support for Capital Expenditures necessary to meet the reliability need between June 1, 2022 and December 31, 2022.

Owner shall file on or before April 1, 2021, in accordance with the Informational Exchange and Challenge Procedures detailed below, appropriate support for the capital expenditures and costs that will be collected as an expense during the Term in calendar year 2022 (June 1, 2022 to December 31, 2022) as detailed below. The Annual Fixed Revenue Requirement, the Maximum Monthly Fixed Cost Payment, and the Fixed O & M/Return on Investment component of the Monthly Fuel Cost Charge for the relevant period of the Term in Schedule 3 will be updated in accordance with the Methodology and shall exclude true-up of investment and expense items disallowed by the Commission, if any.

2. 2022 Filing:

i. Support for Capital Expenditures that will be necessary to meet the reliability need in calendar year 2023

Owner shall file on or before April 1, 2022, in accordance with the Informational Exchange and Challenge Procedures detailed below, appropriate support for the capital expenditures and costs that will be collected as an expense during calendar year 2023 (January 1, 2023 to December 31, 2023) as detailed below. The Annual Fixed Revenue Requirement, the Maximum Monthly Fixed Cost Payment, and the Fixed O & M/Return on Investment component of the Monthly Fuel Cost Charge for the relevant period of the Term in Schedule 3 will be updated in accordance with the Methodology and shall exclude true-up of investment and expense items disallowed by the Commission, if any.

ii. Update to Net Plant for All Components of Rate Base including Capital Expenditures incurred prior to the Term included in Rate Base, Updated Projected Capital Expenditures to be Expensed During the Term, and Operations and Maintenance Expense ~~and One Eighth O&M Cash Working Capital~~, Administrative and General Expense, ~~and~~ Taxes Other Than Income Taxes, and Federal Income Taxes that will be incurred during the Term

The Owner shall also file on or before April 1, 2022, in accordance with the Informational Exchange and Challenge Procedures detailed below, to update the Annual Fixed Revenue Requirement, the Maximum Monthly Fixed Cost Payment, and the Fixed O & M/Return on Investment component of the Monthly Fuel Cost Charge provided for and calculated in accordance with Schedule 3 above with updated projections for all components of rate base including capital expenditures incurred prior to the Term that will be included in rate base, and other costs including operations and maintenance expense~~ and one eighth O&M cash working capital allowance~~, administrative and general expense, ~~and~~ taxes other than income taxes, and federal income taxes that Owner is estimated and projected to incur to maintain and operate the ~~Resource~~Resources and LNG Terminal during the Term based upon information contained in Owner's books and records. At this time, net plant will be updated to include actual capital expenditures and depreciation incurred between January 1, 2018 and December 31, 2021.

3. 2023 Filing:

i. Support for Capital Expenditures that will be necessary to meet the reliability need between January 1, 2024 and May 31, 2024.

Owner shall file on or before April 1, 2023, in accordance with the Informational Exchange and Challenge Procedures detailed below, appropriate support for the capital expenditures and costs that will be collected as an expense during the Term in calendar year 2024 (January 1, 2024 to May 31, 2024) as detailed below. The Annual Fixed Revenue Requirement, the Maximum Monthly Fixed Cost Payment, and the Fixed O & M/Return on Investment component of the Monthly Fuel Cost Charge for the relevant period of the Term in Schedule 3 will be updated in accordance with the Methodology and shall exclude true-up of investment and expense items disallowed by the Commission, if any Methodology and shall exclude true-up of investment and expense items disallowed by the Commission, if any.

ii. True-Up to Actual Costs for All Components of Rate Base including Capital Expenditures incurred prior to the Term included in Rate Base, Capital Expenditures expensed during the Term, and Operations and Maintenance Expense~~ and One Eighth O&M Cash Working Capital~~, Administrative and General Expense, ~~and~~ Taxes Other Than Income Taxes, and Federal Income Taxes incurred during calendar year 2022

The Owner shall also file on or before April 1, 2023, in accordance with the Informational Exchange and Challenge Procedures detailed below, to true-up the Annual Fixed Revenue Requirement, the Maximum Monthly Fixed Cost Payment, and the Fixed O & M/Return on Investment component of the Monthly Fuel Cost Charge provided for and calculated in accordance with Schedule 3 above as updated prior to the Term in the 2022 Filings (sections ~~B~~C(2)(i) and ~~B~~C(2)(ii)) to the costs actually incurred ~~for~~, as adjusted for the True-up Limitations, for all components of rate base including capital expenditures to be included in rate base, ~~.~~capital expenditures expensed to meet the reliability need during the Term in 2022 (June 1, 2022 to December 31, 2022), and other costs including operations and maintenance expense ~~and one eighth O&M cash working capital allowance~~, administrative and general expense, ~~and~~ taxes other than income taxes, and federal income taxes incurred by Owner for maintaining and operating the Resources and LNG Terminal ~~Resource~~ during the Term in 2022 (June 1, 2022 to December 31, 2022) based upon information contained in Owner's books and records. For capital expenditures previously identified as being necessary to meet the reliability need, this filing will only true-up the amount for each capital expenditures to actuals, not whether a capital expenditure should have been designated as necessary to meet the reliability need. Emergent capital expenditures will be subject to review as to whether they are necessary to meet the reliability need under the Informational Exchange and Challenge Procedures. Owner shall submit in accordance with the Informational Exchange and Challenge Procedures below the information necessary to true-up 2022 estimated and projected costs to actual costs. The Methodology includes the mechanism for determining the actual costs incurred by the Owner, subject to the True-up Limitations. Actual costs may increase or decrease the Annual Fixed Revenue Requirement, the Maximum Monthly Fixed Cost Payment, and the Fixed O & M/Return on Investment component of the Monthly Fuel Cost Charge, so the true-up adjustment may be made in either a positive or negative direction. The difference between the Annual Fixed Revenue Requirement, the Maximum Monthly Fixed Cost Payment, and the Fixed O & M/Return on Investment component of the Monthly Fuel Cost Charge provided for and calculated in accordance with Schedule 3 above, as adjusted prior to the Term in the 2022 Filing, and the actual costs in accordance with the Methodology, plus interest determined in accordance with the Commission's interest rate on refunds (18 C.F.R § 35.19a), will be added to or subtracted from the 2024 calendar year Annual Fixed Revenue Requirement, the Maximum Monthly Fixed Cost Payment, and the Fixed O & M/Return on Investment component of the Monthly Fuel Cost Charge.

4. 2024 Filing:

i. True-Up to Actual Costs for All Components of Rate Base including Capital Expenditures expensed during the Term, and Operations and Maintenance Expense ~~and One Eighth O&M Cash Working Capital~~, Administrative and General Expense, ~~and~~ Taxes Other Than Income Taxes, and Federal Income Taxes incurred during calendar year2023

The Owner shall file on or before April 1, 2024, in accordance with the Informational Exchange and Challenge Procedures detailed below, to true-up the Annual Fixed Revenue Requirement, the Maximum Monthly Fixed Cost Payment, and the Fixed O&M/Return on Investment component of the Monthly Fuel Cost Charge provided for and calculated in accordance with Schedule 3 above as updated and modified in the 2022 Filing (~~section B~~Section C(2)(ii)), the 2023 capital expense Filing (~~section B~~Section C(3)(i)), and the 2023 true-up Filing (~~section B~~Section C(3)(ii)), to the costs actually incurred ~~for~~, as adjusted for the True-up Limitations, for all components of rate base including capital expenditures to be included in rate base, capital expenditures expensed to meet the reliability need during the Term in 2023 (January 1, 2023 to December 31, 2023), and other costs including operations and maintenance expense ~~and one eighth O&M cash working capital allowance~~, administrative and general expense, ~~and~~ taxes other than income taxes, and federal income taxes incurred by Owner for maintaining and operating the ~~Resource~~Resources and LNG Terminal during the Term in 2023 (January 1, 2023 to December 31, 2023) based upon information contained in Owner's books and records. For capital expenditures previously identified as being necessary to meet the reliability need, this filing will only true-up the amount for each capital expenditures to actuals, not whether a capital expenditure should have been designated as necessary to meet the reliability need. Emergent capital expenditures will be subject to review as to whether they are necessary to meet the reliability need under the Informational Exchange and Challenge Procedures. Owner shall submit in accordance with the Informational Exchange and Challenge Procedures below the information necessary to true-up 2023 estimated and projected costs to actual costs. The Methodology includes the mechanism for determining the actual costs incurred by the Owner, subject to the True-up Limitations. Actual costs may increase or decrease the Annual Fixed Revenue Requirement, the Maximum Monthly Fixed Cost Payment, and the Fixed O & M/Return on Investment component of the Monthly Fuel Cost Charge, so the true-up adjustment may be made in either a positive or negative direction. The difference between the Annual Fixed Revenue Requirement, the Maximum Monthly Fixed Cost Payment, and the Fixed O & M/Return on Investment component of the Monthly Fuel Cost Charge provided for and calculated in accordance with Schedule 3 above, as adjusted prior to the Term in the 2022 Filing, and the actual costs in accordance with the Methodology, plus interest determined in accordance with the Commission's interest rate on refunds (18 C.F.R. § 35.19a), will be added to or subtracted from the 2024 calendar year Annual Fixed Revenue Requirement, the Maximum Monthly Fixed Cost Payment, and the Fixed O & M/Return on Investment component of the Monthly Fuel Cost Charge. The difference between the Annual Fixed Revenue Requirement, the Maximum Monthly Fixed Cost Payment, and the Fixed O & M/Return on Investment component of the Monthly Fuel Cost Charge provided for and calculated in accordance with Schedule 3 above, as adjusted and the actual costs in accordance with the Methodology, plus interest determined in accordance with the Commission's interest rate on refunds (18 C.F.R § 35.19a), will be settled within 60 days of the Informational Filing detailed below, unless otherwise ordered by the Commission. Any allocation among Interested Parties for resettling of refunds or surcharges will be in

accordance with the ISO Tariff, unless another manner of collection is directed by FERC.

5. 2025 Filing:

i. True-Up to Actual Costs for Capital Expenditures expensed during the Term, and Operations and Maintenance Expense ~~and One Eighth O&M Cash Working Capital~~, Administrative and General Expense, ~~and~~ Taxes Other Than Income Taxes, and Federal Income Taxes incurred between January 1, 2024 and May 31, 2024

The Owner shall file on or before April 1, 2025, in accordance with the Informational Exchange and Challenge Procedures detailed below, to true-up the Annual Fixed Revenue Requirement, the Maximum Monthly Fixed Cost Payment, and the Fixed O&M/Return on Investment component of the Monthly Fuel Cost Charge provided for and calculated in accordance with Schedule 3 above and updated in the 2022 Filing (section ~~B~~C(2)(ii)), the 2023 capital expense Filing (section ~~B~~C(3)(i)), and the 2023 true-up Filing (section ~~B~~C(3)(ii)), to the costs actually incurred, as adjusted for the True-up Limitations, for capital expenditures expensed during the Term in 2024 (January 1, 2024 to May 31, 2024), and other costs including operations and maintenance expense ~~and one eighth O&M cash working capital~~, administrative and general expense, ~~and~~ taxes other than income taxes, and federal income taxes incurred by Owner for maintaining and operating the ~~Resource~~Resources and LNG Terminal during the Term in 2024 (January 1, 2024 to May 31, 2024) based upon information contained in Owner's books and records. For capital expenditures previously identified as being necessary to meet the reliability need, this filing will only true-up the amount for each capital expenditures to actuals, not whether a capital expenditure should have been designated as necessary to meet the reliability need. Emergent capital expenditures will be subject to review as to whether they are necessary to meet the reliability need under the Informational Exchange and Challenge Procedures. Owner shall submit in accordance with the Informational Exchange and Challenge Procedures below the information necessary to true-up 2024 estimated and projected costs to actual costs. The Methodology includes the mechanism for determining the actual costs incurred by the Owner. Actual costs may increase or decrease the Annual Fixed Revenue Requirement, the Maximum Monthly Fixed Cost Payment, and the Fixed O & M/Return on Investment component of the Monthly Fuel Cost Charge, so the true-up adjustment may be made in either a positive or negative direction~~.~~, subject to the True-up Limitations. The difference between the Annual Fixed Revenue

Requirement, the Maximum Monthly Fixed Cost Payment, and the Fixed O & M/Return on Investment component of the Monthly Fuel Cost Charge provided for and calculated in accordance with Schedule 3 above, as adjusted prior to the Term in the 2022 Filing, and the actual costs in accordance with the Methodology, plus interest determined in accordance with the Commission's interest rate on refunds (18 C.F.R. § 35.19a), will be added to or subtracted from the 2024 calendar year Annual Fixed Revenue Requirement, the Maximum Monthly Fixed Cost Payment, and the Fixed O & M/Return on Investment component of the Monthly Fuel Cost Charge. The difference between the Annual Fixed Revenue Requirement, the Maximum Monthly Fixed Cost Payment, and the Fixed O & M/Return on Investment component of the Monthly Fuel Cost Charge provided for and calculated in accordance with Schedule 3 above, as adjusted and the actual costs in accordance with the Methodology, plus interest determined in accordance with the Commission's interest rate on refunds (18 C.F.R § 35.19a), will be settled within 60 days of the Informational Filing detailed below, unless otherwise ordered by the Commission. Any allocation among Interested Parties for resettling of refunds or surcharges will be in accordance with the ISO Tariff, unless another manner of collection is directed by FERC.

II. Informational Exchange and Challenge Procedures for each True-Up

Section 1. Applicability

The following Information Exchange and Challenge Procedures shall apply to the finalization for each True-Up.

Section 2. Informational Posting

A. On or before April 1 of each Filing year as provided above, Owner shall submit to ISO its Filing as detailed above, in accordance with the Methodology. If the date for submission of the Filing falls on a weekend or a holiday recognized by FERC, then the posting shall be due on the next business day. Within two (2) business days of such Filing, ISO shall provide notice of the Filing via a posting on its website and OASIS. The date on which such posting occurs shall be that year's "Publication Date." ISO shall provide notice of such posting via an email exploder list.

Interested Parties can subscribe to the ISO exploder list on the ISO website. Any delay in the Publication Date will result in an equivalent extension of time for the submission of Information Requests discussed in section 3 of these protocols. If the Filing will support the capital expenditures that will be incurred during the Term it shall:

(1) Provide an explanation of need that explains why the capital expenditure is necessary in order to meet the obligations of the Agreement;

(2) Demonstrate that the expenditure is reasonably determined to be the least-cost commercially reasonable option consistent with Good Utility Practice to meet the obligations of the Agreement; and

(3) Include a description of the project(s), the need for the project(s), the alternatives considered with respect to the least-cost alternatives, the expected start and completion date(s), and the project costs.

If the Filing provides for an update of projected costs or a true-up it shall:

(1) Include a workable data-populated template and underlying workpapers in native format with all formulas and links intact;

(2) Provide the template rate calculations and all inputs thereto, as well as supporting documentation and workpapers for data that are used in the formula rate that are not otherwise available in the methodology provided below in the Methodology;

(3) Provide sufficient information to enable Interested Parties to replicate the calculation of the formula results from the methodology provided below in the Methodology;

(4) Identify any changes in the formula references (page and line numbers) to the methodology provided below in the Methodology;

(5) Include the information that is reasonably necessary to determine that Owner has applied the methodology provided below in the Methodology, the extent of any accounting or

other changes that affect the inputs into that methodology, and any corrections or adjustments made in the calculation;

(6) With respect to any change in accounting that affects inputs to the methodology provided below in the Methodology or the resulting charges billed:

a. Identify any accounting changes, including

i. The initial implementation of an accounting standard or policy;

ii. the initial implementation of accounting practices for unusual or unconventional items;

iii. correction of errors and prior period adjustments that impact the Annual Fixed Revenue Requirement;

iv. the implementation of new estimation methods or policies that change prior estimates; and

v. changes to income tax elections;

b. Identify items included in the formula rate at an amount other than on a historic cost basis (e.g., fair value adjustments);

c. Identify any reorganization or merger transaction during the previous year and explain the effect of the accounting for such transaction(s)on inputs to the formula rate in the methodology provided below in the Methodology; and

d. Provide a narrative explanation of the impact of account changes on inputs to the Methodology.

The Owner shall hold an open meeting among Interested Parties ("Annual Meeting") between the Publication Date and May 1 at its offices, with the option for participants to access the meeting by remotely (remote access options may include telephone, video conferencing, webinar, internet conferencing, or other appropriate remote access options as determined by Owner). No less than twenty (20) days prior to such Annual Meeting, the Owner shall provide notice on ISO's internet website and

OASIS of the time, date, and location of the Annual Meeting and ISO shall provide notice of such meeting to an email exploder list. The Owner will also host a Technical Session ("Technical Session") by June 1 of each year. The Technical Session shall provide (1) the Owner the opportunity to explain the Filing in more detail than at the Annual Meeting and (2) Interested Parties an opportunity to seek additional information and clarifications and otherwise discuss the components of the Filing. The Owner shall make available to Interested Parties remote access to this Technical Session. No less than seven (7) days prior to such Technical Session, the Owner shall provide a notice of the Technical Session and request that ISO-NE distribute such notice to the Interested Parties and post it to the ISO-NE website. Interested Parties may receive notice of such posting by subscribing to the associated webpage on the ISO-NE website. For purposes of these procedures, the term Interested Party includes, but is not limited to, customers subject to charges under the Agreement, parties to the FERC proceeding in which this Agreement is submitted, state utility regulatory commissions, the ISO, the ~~ISO~~New England Power Pool Participants Committee, consumer advocacy agencies, and state attorneys general. The Annual Meeting and Technical Session shall (i) permit the Owner to explain and clarify its Filing and (ii) provide Interested Parties an opportunity to seek information and clarifications from the Owner about the Filing.

Section 3. Information Exchange Procedures

The Filing shall be subject to the following information exchange procedures ("Information Exchange Procedures"):

A. Interested Parties shall have until June 1 to serve reasonable information and document requests on Owner ("Information Exchange Period"). If June 1 falls on a weekend or a holiday recognized by FERC, the deadline for submitting all information and document requests shall be extended to the next business day. If the Filing will substantiate the capital expenditures that will be incurred during the Term, such information and document requests shall be limited to what ~~is~~may be reasonably necessary to determine:

a. Whether the capital expenditure is necessary in order to meet the obligations of the Agreement;

b. Whether the expenditure is reasonably determined to be the least-cost commercially reasonable option consistent with Good Utility Practice to meet the obligations of the Agreement; and

c. Whether either of the following occurred: (i) the project was scheduled for before the Term but delayed into the Term, or (ii) the project is scheduled for during the Term but should have been completed prior to the Term.

B. If the Filing provides for an update of projected costs or a true-up, such information and document requests shall be limited to what ~~is~~may be reasonably necessary to determine:

(1) the extent or effect of an accounting change;

(2) whether the Filing fails to include data properly recorded in accordance with these protocols;

(3) the proper application of the Methodology provided below and procedures in these protocols;

(4) the accuracy of data and consistency with the Methodology of the charges shown in the Filing;

(5) the prudence of actual costs and expenditures;

(6) the actual amount of any capital expenditure; and

(7) any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the Methodology.

The information and document requests shall not otherwise be directed to ascertaining whether the Methodology is just and reasonable.

C. The Owner shall make a good faith effort to respond to information and document requests pertaining to the Filing within fifteen (15) business days of receipt of such requests. The Owner shall respond to all information and document requests by no later than July 10.

D. The Owner will cause to be on the ISO website and OASIS all information requests from Interested Parties and the Owner's response(s) to such requests; except, however, if responses to information and document requests include material deemed by the Owner to be confidential information, such information will not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement to be executed by the Owner and the requesting party.

E. Owner shall not claim that responses to information and document requests provided pursuant to these protocols are subject to any settlement privilege in any subsequent FERC proceeding addressing an Owner's Filing.

F. To the extent the Owner and applicable Interested Parties are unable to resolve disputes related to information request, the Owner or applicable Interested Parties may avail themselves of the on-call settlement judge of the Commission's Office of Administrative Law Judges and Dispute Resolution to resolve such matters.

Section 4. Challenge Procedures

A. Interested Parties shall have until July 31 following the Publication Date to review the inputs, supporting explanations, allocations, and calculations and to notify the Owner in writing, which may be made electronically, of any specific Informal Challenges. The period of time from the Publication Date until July 31 shall be referred to as the Review Period. If July 31 falls on a weekend or a holiday recognized by FERC, the deadline for submitting all Informal Challenges shall be extended to the next business day. The July 31 deadline will be tolled for each day Owner fails to respond to reasonable requests for information provided in Section II.3(A) and (B) by the July 10 deadline provided in Section II.3(C). Failure to pursue an issue through an

Informal Challenge ~~or to lodge~~shall not bar pursuit of that issue as part of a Formal Challenge with respect to the same Filing as long as the Interested Party has submitted an Informal Challenge on any issue with respect to that Filing. Failure to submit a Formal Challenge regarding any issue as to a given Filing shall bar pursuit of such issue with respect to that same Filing but shall not bar pursuit of such issue or the submission of a Formal Challenge as to such issue as it relates to a subsequent Filing or changes to filings in Section II.5 below.

B. A party submitting an Informal Challenge must specify the inputs, supporting explanations, allocations, calculations, or other information to which it objects, and provide an appropriate explanation and documents, as applicable, to support its challenge. The Owner shall make a good faith effort to respond to any Informal Challenge within fifteen (15) business days of notification of such challenge. The Owner shall appoint a senior representative to work with the party that submitted the Informal Challenge (or its representative) toward a resolution of the challenge. If the Owner disagrees with such challenge, the Owner will provide the Interested Party(ies) with a written explanation supporting the inputs, supporting explanations, allocations, calculations, or other information. Subject to the confidentiality provisions in Section II.3D above, the Owner shall not claim that responses to information and document requests pursuant to these Protocols are subject to any settlement privilege in any subsequent Commission proceeding addressing the Owner's Filing, or any other FERC proceeding and in any proceeding before an Article III court to review a FERC decision. No Informal Challenge may be submitted after July 31, and the Owner must respond to all Informal Challenges by no later than August 31, unless the Review Period is extended by the Owner or FERC. The Owner shall cause to be posted publicly all Informal Challenges from Interested Parties and the Owner's response(s) to such Informal Challenges; except, however, if Informal Challenges or responses to Informal Challenges include material deemed by the Owner to be confidential information, such information will not be publicly posted but will be provided by the Owner to requesting parties pursuant to a confidentiality agreement to be executed by the Owner and the requesting party. In such a case, there will be a notice posted that the information requested is available pursuant to a confidentiality agreement.

C. Informal Challenges shall be subject to the resolution procedures and limitations in this section. Formal Challenges shall be filed pursuant to these protocols and shall satisfy all of the following requirements.

(1) A Formal Challenge shall, as applicable:

a. Clearly identify the action or inaction which is alleged to violate the- Methodology or protocols;

b. Explain how the action or inaction violates the Methodology or protocols;

c. Provide an explanation of why the capital expenditure is not necessary in order to meet the obligations of the Agreement;~~(~~

d. ~~d)~~ Demonstrate that the expenditure is not reasonably determined to be the least-cost commercially reasonable option consistent with Good Utility Practice to meet the obligations of the Agreement;

e. Set forth the business, commercial, economic or other issues presented by the action or inaction as such relate to or affect the party filing the Formal Challenge, which may include:

i. The extent or effect of an accounting change;

ii. Whether the Filing fails to include data properly recorded in accordance with these protocols;

iii. The proper application of the Methodology and procedures in these protocols;

iv. The accuracy of data and consistency with the Methodology of the charges shown in the Filing;

v. The prudence of actual costs and expenditures; or

vi. Any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the Methodology.

f. Make a good faith effort to quantify the financial impact or burden (if any) created for the party filing the Formal Challenge as a result of the action or inaction;

g. State whether the issues presented are pending in an existing Commission proceeding or a proceeding in any other forum in which the filing party is a party, and if so, provide an explanation why timely resolution cannot be achieved in that forum;

h. State the specific relief or remedy requested, including any request for stay or extension of time, and the basis for that relief;

i. Include all documents that support the facts in the Formal Challenge in possession of, or otherwise attainable by, the filing party, including, but not limited to, contracts and affidavits; and

j. State whether the filing party utilized the Informal Challenge procedures described in these protocols to dispute the action or inaction raised by the Formal Challenge, and, if not, describe why not.

(2) Service. Any person filing a Formal Challenge must serve a copy of the Formal Challenge on the Owner. Service to the Owner must be simultaneous with filing at the Commission. Simultaneous service can be accomplished by electronic mail in accordance with § 385.2010(f)(3). The party filing the Formal Challenge shall serve the individual listed as the contact person on the Owner's Informational Filing required under Section II.6 of these protocols.

~~D. Informal and formal Challenges shall be limited to all issues that may be necessary to determine: (1) the extent or effect of an Accounting Change; (2) whether the Filing fails to include data properly recorded in accordance with these protocols; (3) the proper application of the methodology provided below in section III and procedures in these protocols; (4) the accuracy of data and consistency with the methodology provided below in section III of the charges shown in the Filing; (5) the prudence of actual costs and expenditures; (6) whether a capital expenditure incurred during the Term is necessary in order to meet the obligations of the Mystic Agreement; (7) whether a capital expenditure incurred during the Term is reasonably determined to be the least-cost commercially reasonable option consistent with Good Utility Practice to meet the obligations of the Mystic Agreement; or (8) any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the methodology provided below in section III.~~

D. ~~E.~~ Any changes or adjustments to the Filing resulting from the Information Exchange and Informal Challenge processes that are agreed to by the Owner will be reported in the Informational Filing required pursuant to Section II.6 of these protocols and will be addressed as discussed in Section II.5 of these protocols.

E. ~~F.~~ An Interested Party shall have until ~~October~~November 15 following the Review Period to make a Formal Challenge with FERC, which shall be served on the Owner on the date of such filing as specified in Section II.4.C(2) above. A Formal Challenge shall be filed in the same docket as the Owner's Informational Filing discussed in Section II.6 of these protocols. The ~~Transmission~~ Owner shall respond to the Formal Challenge by the deadline established by FERC. A party may not pursue a Formal Challenge if that party did not submit an Informal Challenge on any issue during the applicable Review Period.

F. ~~G.~~ In any proceeding initiated by FERC concerning the Filing or in response to a Formal Challenge, the Owner shall bear the burden, consistent with section 205 of the Federal Power Act, of proving that (i) it has correctly applied the terms of the Methodology consistent with these protocols, and (ii) in the case of capital expenditures that are expensed during the Term of the Agreement, that the capital expenditure is necessary in order to meet the obligations of the Agreement, and that the expenditure is reasonably determined to be the least-cost commercially reasonable option consistent with Good Utility Practice to meet the obligations of the Agreement. Nothing herein is intended to alter the burdens applied by FERC with respect to prudence challenges.

G. ~~H.~~ Except as specifically provided herein, nothing herein shall be deemed to limit in any way the right of the Owner to file unilaterally, pursuant to Federal Power Act section 205 and the regulations thereunder, to change the Methodology or any of its inputs (including, but not limited to, rate of return), or the right of any other party to request such changes pursuant to section 206 of the Federal Power Act and the regulations thereunder.

H. ~~I.~~ No party shall seek to modify the Methodology under the Challenge Procedures set forth in these protocols and Filings shall not be subject to challenge by anyone for the purpose of modifying the Methodology. Any modifications to the Methodology will require, as applicable, a Federal Power Act section 205 or section 206 filing.

Section 5. Changes to the Filings

Any changes to the data inputs, or as the result of any FERC proceeding to consider a Filing, or as a result of the procedures set forth herein, shall be settled by ISO-NE within 60 days of its effective date. Any allocation among Interested Parties for resettling of refunds or surcharges will be in accordance with the ISO Tariff, unless another manner of collection is directed by FERC. Interest on any refund or surcharge shall be calculated in accordance with 18 C.F.R. § 35.19a (“FERC’s Interest Rate”).

Section 6. Informational Filing

A. By September 15 following the Publication Date, the Owner shall submit to FERC an informational filing (“Informational Filing”) of its Filing. This Informational Filing must include, if applicable, the information that is reasonably necessary to determine: (1) that input data under the Methodology are properly recorded in any underlying workpapers; (2) that the Owner has properly applied the Methodology and these procedures; (3) the accuracy of data and the consistency with the Methodology of the Annual Fixed Revenue Requirement; (4) the extent of accounting changes that affect inputs; (5) whether a capital expenditure collected as an expense during the Term is necessary in order to meet the obligations of the Agreement; and (6) whether a capital expenditure collected as an expense during the Term is reasonably determined to be the least-cost commercially reasonable option consistent with Good Utility Practice to meet the obligations of the Agreement. The Informational Filing must also describe any corrections or adjustments made during that period, and must describe all aspects of the Methodology or its inputs that are the subject of an ongoing dispute under the Informal or Formal Challenge procedures. Within five (5) days of such Informational Filing, ISO shall provide notice of the Informational Filing by posting the docket number assigned to each Owner's Informational Filing on the ISO website and OASIS and via an email exploder list.

B. Any challenges to the implementation of the Methodology must be made through the Challenge Procedures described in Section II.4 of these protocols or in a separate complaint proceeding, and not in response to the Informational Filing.

III. Methodology

The true-up methodology template is provided below.

CERTIFICATE OF SERVICE

In accordance with Rule 2010 of the Commission's Rules of Practice and Procedure, I hereby certify that I have this day served by electronic mail a copy of the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, DC this 2nd day of November, 2018.

/s/ Phyllis G. Kimmel

Phyllis G. Kimmel
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