The Commonwealth of Massachusetts

DEPARTMENT OF PUBLIC UTILITIES

D.P.U. 17-146-B February 1, 2019

Inquiry by the Department of Public Utilities on its own Motion into the eligibility of energy storage systems to net meter pursuant to G.L. c. 164, §§ 138-140 and 220 CMR 18.00, and application of the net metering rules and regulations relating to the participation of certain net metering facilities in the Forward Capacity Market pursuant to Net Metering Tariff, D.P.U. 09-03-A (2009).

NET METERING, SMART PROVISION, AND THE FORWARD CAPACITY MARKET

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I. INTRODUCTION AND PROCEDURAL HISTORY

On October 3, 2017, the Department of Public Utilities ("Department") opened this inquiry to investigate two issues: (1) the eligibility of energy storage systems ("ESS") to net meter, and the appropriate definition of ESS for net metering ("NM") purposes, pursuant to 220 CMR 18.00; and (2) the qualification and participation of certain NM facilities in the Forward Capacity Market ("FCM") administered by ISO New England Inc. ("ISO-NE"), pursuant to Net Metering Tariff, D.P.U. 09-03-A (2009). Net Metering, Energy Storage Systems, and the Forward Capacity Market Inquiry, D.P. U. 17-146 (2017).[1] The Department bifurcated its investigation in this docket. On February 1, 2019, the Department issued its Order addressing the eligibility of ESS to net meter, and the appropriate definition of ESS for NM purposes. D.P.U. 17-146-A (February 1, 2019).

On September 12, 2017, Fitchburg Gas and Electric Light Company d/b/a Unitil ("Unitil"), Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid ("National Grid"), and NSTAR Electric Company and Western Massachusetts Electric Company, each d/b/a Eversource Energy ("Eversource")[2] (individually "Distribution Company" and collectively "Distribution Companies") filed a Solar Massachusetts Renewable

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[1] Through inquiries and public comments received in relevant dockets, stakeholders expressed a desire for the Department to explore both the eligibility of ESS to net meter and the participation of certain NM facilities in the FCM. Tesla, Inc., D.P.U. 17-105 (2017); Genbright LLC, D.P.U. 16-116 (2017); Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 15-155, Interlocutory Order on Scope of Proceeding at 6-7 (February 9, 2016).

[2] The SMART Provision was originally filed by NSTAR Electric Company and Western Massachusetts Electric Company. Effective December 31, 2017, Western Massachusetts Electric Company merged into NSTAR Electric Company following the Department's approval in NSTAR Electric Company, D.P.U. 17-05, at 44, 765 (2017).

Target ("SMART") tariff ("SMART Provision") to implement the SMART program established pursuant to An Act Relative to Solar Energy, St. 2016, c. 75, § 11(b), G. L. c. 25A, § 6, and 225 CMR 20.00. Solar Massachusetts Renewable Target Provision, D.P.U. 17-140. The filing raised issues related to qualification and participation in the FCM. In a Hearing Officer Memorandum dated March 7, 2018, the Department announced that the scope of the D.P.U. 17-140 proceeding would be limited to examination into all matters of the SMART Provision excluding FCM matters and that the Department would address the issue of qualifying distributed generation facility participation in the FCM in D.P.U. 17-146 or a subsequent docket. D.P.U. 17-140, Hearing Officer Memorandum at 2 (March 7, 2018). On September 26, 2018, the Department issued its Order that included a determination regarding the interim treatment of capacity for facilities participating in the SMART Program between the date of the SMART program's commercial operation date and the date of the FCM Order in D.P.U. 17-146 ("Interim Period"). Order Approving Model Smart Provision, D.P.U. 17-140-A at 123-129 (2018). In this instant Order, the Department addresses the qualification and participation in the FCM of distributed generation facilities participating in the NM and SMART programs.

In this docket, the Department sought written comments on a series of questions related to the qualification and participation of certain distributed generation facilities participating in the NM and SMART programs ("NM and SMART facilities") in the FCM.[3] Following receipt

[3] The Department sought two rounds of initial comments and three rounds of reply comments in this docket with regard to the qualification and participation of certain NM and SMART facilities in the FCM. The Department has reviewed and considered all comments received in this docket. While we summarize many of the comments received in this docket throughout this Order, we do not attempt to summarize all comments received and considered in our decision. The Department received comments from the following entities: AES Distributed Energy ("AES"); Avid Solar LLC; Bay State

of initial and reply comments, the Department developed a straw proposal issued to stakeholders on May 30, 2018 (Hearing Officer Memorandum (May 30, 2018), Appendix A ("Initial Straw Proposal")). The Department held a technical conference on June 4, 2018, and facilitated a discussion based on the information contained in written comments and the Department's Initial Straw Proposal. Following the technical conference, the Department issued a revised straw proposal ("Revised Straw Proposal") and sought further written comments (Hearing Officer Memorandum (June 19, 2018)). On July 25, 2018, DOER filed reply written comments that included a "Compromise Proposal: Framework for Title to Capacity Rights of Net Metering and SMART Facilities" developed jointly by ten stakeholders ("Compromise Proposal"). Following receipt of an Emergency Request for an Extension of the Comment Period filed by Genbright, the Department extended the deadline to file reply written comments limited in scope to the Compromise Proposal. In this Order, the Department clarifies the NM and SMART program rules applicable to qualification and participation in the FCM.

Hydropower Association ("BSHA"); Borrego Solar Systems, Inc. ("Borrego Solar"); Cape Light Compact JPE ("Compact"); Clean Energy Group ("CEG"); CPower; Department of Energy Resources ("DOER"); Energy Management, Inc. ("EMI"); Edison Electric Institute ("EEI"); EnerNOC; Genbright LLC ("Genbright"); Green Charge and Stem, Inc.; National Grid; Metropolitan Area Planning Council ("MAPC"); Northeast Clean Energy Council ("NECEC"); Eversource; Office of the Attorney General ("Attorney General"); PowerOptions; Scrum Inc. ("Scrum"); Sunesty Energy Catalysts LLC ("Sunesty"); Sunrun, Inc. ("Sunrun"); Tesla, Inc. ("Tesla"); The Cadmus Group, Inc. ("Cadmus"); The Energy Consortium; Town of Nantucket ("Nantucket"); and ViZn Energy Systems, Inc. ("ViZn").

II. BACKGROUND

A. Net Metering

Under the statutory and regulatory framework in Massachusetts, NM allows customers to receive credits for excess electricity that NM facilities generate. To qualify for the general NM program, a customer may install any type of generating facility, regardless of fuel source, as long as the facility is 60 kilowatts ("kW") or less. 220 CMR 18.02. Facilities of up to two megawatts ("MW"), or ten MW in the case of certain public facilities, are eligible for NM if they generate electricity with renewable fuels (i.e., wind, solar photovoltaics, and anaerobic digestion). 220 CMR 18.02. On August 24, 2012, the Department issued Net Metering, D.P.U. 11-11-C (2012), clarifying which projects are eligible for net metering and which are not. D.P.U. 11-11-C at 21-23. On November 17, 2017, the Department issued an Order in D.P.U. 17-10 creating a small hydroelectric NM program pursuant to G.L. c. 164, § 139A ("SHP").[4] Net Metering Rulemaking, D.P.U. 17-10 (2017). To qualify for the SHP, a customer may install a facility that uses water to generate electricity, as long as the facility is two MW or less. 220 CMR 18.02.

B. SMART Program

In compliance with An Act Relative to Solar Energy, St. 2016, c. 75, § 11(b), DOER promulgated regulations for effect August 25, 2017, 225 CMR 20.00, to implement a statewide solar incentive program, the SMART program ("SMART Regulations"). The SMART Regulations establish a voluntary statewide solar incentive program under the auspices of DOER. 225 CMR 20.00. The SMART Regulations encourage the Distribution Companies to

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[4] St. 2016, c. 188, § 10.

jointly develop and submit a tariff to the Department for review and approval. 225 CMR 20.02, 20.05(2), 20.07(3)(a)(11). On September 26, 2018, the Department issued an Order approving the SMART Provision with modifications, directing the Distribution Companies to file a revised model SMART Provision. Order Approving Model SMART Provision, D.P.U. 17-140-A at 197 (September 26, 2018). The Department found that during the Interim Period, neither SMART owners, as defined in 225 CMR 20.02, nor the Distribution Companies may assert title to the capacity of facilities receiving a SMART program incentive payment. D.P.U. 17-140-A at 125.[5] The Department's decision to not assign capacity rights to SMART facilities for the Interim Period only applied to SMART facilities operating as net metering and alternative on-bill credit solar tariff generating units. D.P.U. 17-140-A at 125. The Department approved the model SMART Provision on November 26, 2018, and approved each Distribution Company's SMART Provision on December 21, 2018.[6] The Distribution Companies filed their SMART program reconciling mechanism ("SMART Factor") filing for Department review and approval on November 1-2, 2018 docketed as D.P.U. 18-130 (Until), D.P.U. 18-131 (National Grid), and D.P.U. 18-132 (Eversource). The SMART program reconciling mechanism is structured as an annually reconciling charge and would be applied to all bills issued by the Distribution Company. D.P.U. 17-140-A at 188.

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5 The holder of title to the capacity rights of these facilities could participate in the FCM.

6 On January 25, 2019 the Department approved Unitil's revised SMART Provision, which corrected duplicative tariff numbering and added the rate GD-3 value of energy for 2019.

C. ISO-NE Energy and Capacity Markets

ISO-NE is a not-for-profit, private corporation that serves as the regional transmission organization for New England. ISO-NE operates the New England bulk power system and administers New England's wholesale electricity markets. Investigation Into The Need For Additional Capacity In NEMA/Boston, D.P.U. 12-77, at 1 n.1 (2013). ISO-NE operates three wholesale electricity markets in New England - the energy, capacity, and ancillary services markets. The energy markets provide both day-ahead and real-time wholesale electric energy products to market participants. The FCM projects the needs of the power system three years in advance and then holds an annual auction, the Forward Capacity Auction ("FCA"), in February of each year to purchase power resources to satisfy the region's future needs. Massachusetts Electric Company and Nantucket Electric Company, Interlocutory Order on Scope of Proceeding ("Interlocutory Order"), D.P.U. 15-155, at 2 (2016), citing Investigation Into The Need For Additional Capacity In NEMA/Boston, D.P.U. 12-77, at 5 (2013).

There are two primary ways for a distributed generation facility to participate in the ISO-NE FCM. Facilities may either obtain a capacity supply obligation ("CSO")[7] or elect not to obtain a CSO but earn performance incentive payments under ISO-NE's Pay for Performance ("PFP) Project.[8] There is an annual timeline for participating in the FCM.[9] ISO-NE administers

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7 ISO-NE defines a CSO as an obligation to provide capacity from a resource, or a portion thereof, to satisfy a portion of the region's future needs that is acquired through a FCA in accordance with Section III. 13.2 of its Transmission, Markets and Services Tariff ("ISO Tariff") (also known as Market Rule 1), a reconfiguration auction, Section III 13.4, or a Capacity Supply Obligation Bilateral, Section III 13.5.1 (ISO Tariff, § I.2.2 at 16).

8 ISO-NE defines pay for performance revenues under its PFP, as financial incentives for FCM resource owners to make investments to ensure their resource's reliability and performance during periods of scarcity. ISO-NE, https://www.iso-

the FCA every February to determine which facilities will obtain a CSO for the FCM. ISO-NE Tariff, § III.13. To participate in the FCA, a facility owner must (1) submit a show of interest form in April, prior to the subsequent FCA, and (2) qualify a facility.[10] FCA #14 Schedule.

On March 9, 2018, the Federal Energy Regulatory Commission ("FERC") approved ISO-NE's Competitive Auctions with Sponsored Policy Resources proposal ("CASPR"), which seeks to accommodate the entry of Sponsored Policy Resources[11] into the FCM over time while

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ne.com/participate/support/customer-readiness-outlook/fcm-pfp-project (last visit January 31, 2019). Since ISO-NE implemented the project on June 1, 2018, PFP, capacity performance payments can now be provided to resources that have performed during a capacity scarcity condition despite not being in the FCM or having an FCM CSO. ISO-NE, https://www.iso-ne.com/participate/support/customer-readiness-outlook/fcm-pfp-project (last visit January 31, 2019).

9 ISO-NE publishes annual and monthly FCM calendars with relevant deadlines. ISO-NE, https://www.iso-ne.com/ (last visit January 31, 2019). For example, the FCA #14 schedule for capacity commitment period 2023-2024 is available at https://www.iso-ne.com/static-assets/documents/2017/05/fca-14-timeline-5-9-2017.pdf ("FCA #14 Schedule"); the FCA #15 schedule for capacity commitment period 2024-2025 is available at https://www.iso-ne.com/static-assets/documents/2018/03/fca_15_market_timeline.pdf ("FCA #15 Schedule").

10 For example, if a facility owner seeks to participate in FCA #14 in February 2020 for capacity commitment period 2023-2024, that owner must participate in the show of interest in April 2019. FCA #14 Schedule.

11 The ISO Tariff § I.2.2 defines a Sponsored Policy Resource as "a New Capacity Resource that: receives an out-of-market revenue source supported by a government-regulated rate, charge or other regulated cost recovery mechanism, and: qualifies as a renewable, clean or alternative energy resource under a renewable energy portfolio standard, clean energy standard, alternative energy portfolio standard, renewable energy goal, or clean energy goal enacted (either by statue or regulation) in the New England state from which the resources receives the out-of-market revenue source and that is in effect on January 1, 2018." ISO Tariff § 107.0.0.

maintaining competitive capacity pricing.[12] Order on Tariff Filing, 162 FERC ¶ 61,205, at PP 43-47 (March 9, 2018). According to ISO-NE, the CASPR proposal seeks to mitigate the potential for capacity resources that are compensated through the New England states' "out-of-market-procurements" revenues to create price suppression, which would negatively impact the market's ability to retain and compensate needed existing resources and to attract new, competitively-compensated resources.[13] 162 FERC ¶ 61, 205, at P 6.[14]

D. Net Metering and ISO-NE Energy and Capacity Markets

In 2009, the Department required the Distribution Companies to register all Class II and III NM facilities in the ISO-NE energy market as Settlement Only Generators ("SOG"), and use any energy market payments received from ISO-NE to offset the total costs of NM recovered from all ratepayers through the NM recovery surcharge ("NMRS").[15] D.P.U. 09-03-A at 18-19.

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12 ISO-NE's CASPR proposal phases out the renewable technology resource exemption to the Minimum Offer Price Rule. 162 FERC ¶ 61, 205, at n.14, PP 25 and 87. The CASPR rules will allow for a secondary capacity auction, following the FCA and allows renewable, clean, or alternative technology resources receiving revenue from state or municipal entities outside the ISO-NE markets to acquire a CSO of a retiring capacity resource. 162 FERC ¶ 61, 205, at P 29.

13 FERC's Order also cites ISO-NE's argument that Out of Market Procurements may result in significant overbuild of the wholesale power system and cause consumers to "pay twice" for the same capacity. 162 FERC ¶ 61, 205, at P 24.

14 Several parties in this proceeding comment that ISO-NE's CASPR proposal creates uncertainty of the capacity market value of state policy sponsored resources such as NM or SMART facilities and may reduce or eliminate the capacity value of these resources in future ISO-NE FCAs (Attorney General Comments at 4 (July 5, 2018); Tesla Reply Comments at 3 (July 25, 2018)); National Grid Reply Comments at 12 (February 22, 2018); Eversource Reply Comments at 5 (February 22, 2018)). The Department considers the potential implications of CASPR in its decision.

15 The purpose of the NMRS is for a Distribution Company to recover the NM credits applied to customers and the non-reconciling distribution portion of revenues displaced

The Department currently allows Eversource the option to choose to have behind-the-meter ("BTM") Class II and III NM facilities act as load reducers while National Grid and Unitil must register all facilities as SOGs (National Grid and Eversource ("Companies") Joint Reply Comments at 9 (July 25, 2018)). NSTAR Electric Company, D.P.U. 12-116-B at 5-7 (2014); see Fitchburg Gas and Electric Light Company – M.D.P.U. No. 324; Massachusetts Electric Company and Nantucket Electric Company – M.D.P.U. No. 1404; NSTAR Electric Company – M.D.P.U. No. 68F.

In 2009, the Department also granted the Distribution Companies the right to assert title to the capacity associated with Class II and III NM facilities, but did not obligate the Distribution Companies to participate in the FCM. D.P.U. 09-03-A at 18. A Distribution Company must declare its intent to seek capacity payments when a host customer ("HC") applies for NM services, and the Distribution Company is then obligated to act in a commercially reasonable manner to obtain such capacity payments, which will be applied to offset any NMRS. D.P.U. 09-03-A at 19. See e.g., Fitchburg Gas and Electric Light Company Net Metering Tariff, M.D.P.U. No. 309, § 1.08(8). In D.P.U. 09-03-A, the Department explained that administrative difficulties of bidding the capacity of Class II and III NM facilities into the FCM three years in advance for generation that is owned and operated by third parties who are not contractually bound to the Distribution Company prevented the Department from requiring the Distribution Companies to participate in the FCM. D.P.U. 09-03-A at 19.

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by customers who have installed on-site generation facilities in accordance with G.L. c. 164, §§ 138 and 139. See e.g., Fitchburg Gas and Electric Light Company Net Metering Tariff, M.D.P.U. No. 309, § 1.08(1).

Evidence provided by the close of the record in the instant case indicates that National Grid is the only Distribution Company to assert title to capacity of NM facilities, although it has not yet enrolled the capacity of any NM facilities in the FCM. D.P.U. 17-140-A at 112.[16] Neither Eversource nor Unitil has asserted title to capacity rights for any NM facilities. D.P.U. 17-140-A at 112.[17] In D.P.U. 15-155, National Grid proposed ratemaking treatment for capacity payments associated with NM facilities participating in the FCM. D.P.U. 17-140-A at 112; D.P.U. 15-155, Exh. NG-SN-1, at 2. The Department determined that National Grid's proposal warranted broader inquiry with input from appropriate interested persons and entities and deferred a decision to a subsequent proceeding. Interlocutory Order, D.P.U. 15-155, at 5-7 (2016); D.P.U. 15-155, at 519 (2016). On July 12, 2016, Genbright filed a petition with the Department for a declaratory order pursuant to G.L. c. 30A, § 8 and 220 CMR 2.02 with respect to National Grid complying with D.P.U. 09-03-A (2009) and acting in a commercially reasonable manner to obtain payments for capacity products associated with solar net metering facilities. Subsequently, the Department suspended review of Genbright's petition until the investigation in this inquiry, and the Department's findings regarding the same, are concluded. Genbright, D.P.U. 16-116 (September 12, 2017).

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16 Over the last five years, National Grid had the right to claim title to the capacity of 908 NM facilities but asserted title to only 404 NM facilities. D.P.U. 17-140, Exhs. GB 1-1(a)-(b); SEIA 2-2(a) (Supp.). Although it has asserted title to multiple NM facilities, National Grid has not enrolled the capacity of any net metering facilities in the FCM (Exh. SEIA 2-2(c)-(d)).

17 Eversource had the right to claim title to 252 NM facilities, while Unitil had the right to claim title to 16 NM facilities. D.P.U. 17-140, Exh. GB 1-1(a)-(b).

III. COMPROMISE PROPOSAL

A. Summary

The Compromise Proposal is an agreement by ten stakeholders[18] that recommends rules and procedures ("Framework") for establishing ownership and title to the capacity and energy rights associated with Class II and III NM facilities and SMART facilities that are receiving Alternative On-Bill Credits ("AOBC") (together "DG Facilities") (Compromise Proposal at 1). The Compromise Proposal recommends that the capacity rights of DG Facilities automatically transfer to the Distribution Companies without a requirement to assert title (Compromise Proposal at 1-2). However, the Compromise Proposal recommends that the Distribution Companies not be automatically granted the capacity rights to the following types of distributed generation facilities participating in the NM and SMART programs: (1) Class I NM facilities;[19] (2) ESS paired with a solar generating facility participating in the NM or SMART programs; and (3) any Class II or III NM facility that the Distribution Company has not previously asserted title to under the NM tariff and that the HC has either (a) successfully qualified in any previous FCA or (b) submitted a Qualification Package in the most recent FCA before the date of this Order[20] (Compromise Proposal at 1-2, 5). [21]

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18 The ten stakeholders to the Compromise Proposal include the Attorney General, Borrego Solar, DOER, EnerNOC, Engie Storage, Eversource, National Grid, NECEC, Sunrun and Tesla (collectively "Collaborators") (Compromise Proposal at 1).

19 The Compromise Proposal states that the Framework does not apply to Class I NM facilities (including Class I NM facilities enrolled in SMART) and recommends that the HC should automatically own the rights to both capacity and energy from those facilities (Compromise Proposal at 2).

20 A Class II or III NM facility that the Distribution Company has not previously asserted title under the NM tariff and the HC has successfully qualified in any previous FCA or

Under the Compromise Proposal, Distribution Companies would be required to monetize the capacity of DG Facilities in one of two ways: (1) directly monetize the capacity by qualifying and bidding that capacity into the FCM to obtain a CSO ("Option 1"); or (2) register the DG Facility in the FCM to passively earn performance incentive payments under ISO-NE's PFP rule ("Option 2") (Compromise Proposal at 3).[22]

The Compromise Proposal recommends a revenue sharing mechanism between ratepayers and the Distribution Companies for FCM market revenues and penalties (Compromise Proposal at 3).[23] According to the Compromise Proposal, if a Distribution Company exercises Option 1, the FCM net proceeds, whether net payments or costs, would be shared between ratepayers and the Distribution Company with 80 percent of the net proceeds credited to ratepayers and 20 percent credited to the Distribution Company (Compromise Proposal at 3).[24]

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submitted a Qualification Package in the most recent FCA before the date of this Order, would retain their existing treatment and their status would be unchanged under the Compromise Proposal, even if the HC chooses to subsequently add co-located storage (Compromise Proposal at 2).

[21] The Stakeholders to the Compromise Proposal did not address Qualifying Facilities (National Grid and Eversource ("Companies") Reply Comments at 6 (July 25, 2018)).

[22] If a Distribution Company retains ownership of capacity rights to a co-located solar and ESS facility, the Distribution Company shall not have the right to dispatch a co-located storage facility for the purpose of participating in the ISO-NE markets (Compromise Proposal at 3).

[23] Distribution Companies Revenue/Cost Share = (Net FCM proceeds under Option 1)*(20%) + (Net FCM Proceeds under Option 2) * (0%) (Compromise Proposal at 3).

[24] NMRS/SMART Factors Revenues/Costs = [(Net FCM proceeds under Option 1)*(80%) = (Net FCM proceeds under Option 2)*(100%)]- (distribution company administrative costs) (Compromise Proposal at 3). Any revenues credited to the Distribution Company would not count toward revenues used to calculate the Revenue Decoupling Mechanism or the current or future Earnings Cap or Sharing Mechanism (Compromise Proposal at 3).

If the Distribution Company elects to exercise Option 2, 100 percent of the PFP revenues from the FCM would be credited to ratepayers (Compromise Proposal at 3). The Compromise Proposal recommends that the Distribution Companies be allowed to recover full administrative costs for participation with DG Facilities in the FCM as well as processing of buyout offers (Compromise Proposal at 3). Net proceeds and administrative costs would pass to ratepayers through the NMRS or the SMART Factor (apportioned based on MW) (Compromise Proposal at 3).

The Compromise Proposal also provides a recommended process and formula for a HC of a NM Facility or the owner of a distributed generation facility participating in the SMART program (collectively "Facility Owner") to make a one-time, up-front purchase of capacity rights for the following types of DG Facilities: 1) any new or existing BTM[25] solar DG Facility; and 2) any new or existing front-of-the-meter ("FTM")[26] or BTM solar DG Facility either paired with an ESS or retrofitted by adding a co-located ESS ("eligible facilities"); (Compromise Proposal at 2-4).

For new eligible facilities or existing solar DG Facilities that have been retrofitted by adding a co-located ESS, the Facility Owner may exercise the buyout option at any time after filing an initial or revised interconnection application and before the Distribution Company provides an Authorization to Interconnect ("ATI") (Compromise Proposal at 4-5). If the

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25 For the purposes of the Compromise Proposal and this Order, BTM means a facility that serves an on-site load other than parasitic load or station load utilized to operate the facility (Compromise Proposal at 6).

26 For the purposes of the Compromise Proposal and this Order, FTM means a facility that serves no associated on-site load other than parasitic or station load utilized to operate the generation unit (Compromise Proposal at 3).

Distribution Company has already entered a retrofitted existing facility into the FCM prior to exercise of the buyout option, the Distribution Company would be required to transfer the CSO for that facility to the Facility Owner (Compromise Proposal at 5).[27] For existing eligible facilities, the Facility Owner would be allowed to exercise the buyout option at any time provided the Distribution Company was not in the process of qualifying the resource in the FCM (i.e., has submitted a Show of Interest) or had not already qualified the resource in the FCM for the current qualification period (Compromise Proposal at 5).

B. Method of Review

The Department encourages parties and participants to settle issues through negotiation and compromise because that approach provides an opportunity for creative problem solving, allows parties and participants to reach results in line with their expectations, and it is often a better alternative to adjudication. From time to time, the Department rules on settlement agreements submitted by parties to an adjudicatory proceeding.[28] See Order on Settlement Agreement, D.P.U. 16-162-A (2017). The commenters and technical conference attendees in an inquiry are not parties as defined in 220 CMR 1.01(3). Order on Coalition for Community Solar Access' Motion for Reconsideration, D.P.U. 17-22-B at 6 (2017).

This docket is a Department inquiry. The proceedings in this docket are not adjudicatory proceedings as defined in G.L. c. 30A, § 1 or 220 CMR 1.01(3). While the Department

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27 If a BTM eligible facility chooses to exercise the buyout option, the Distribution Company would be required to delist the facility from ISO-NE as a SOG (Compromise Proposal at 5).

28 A party is defined as a "specifically named person whose legal rights, duties, or privileges are being determined in an adjudicatory proceeding before the Department." 220 CMR 1.01(3); see also, G.L. c. 30A, § 1(3).

appreciates that the Compromise Proposal constitutes an agreement amongst ten of the most active stakeholders in this docket, we also recognize that there are many interested stakeholders that have observed or participated in this docket that did not participate in creation of the Compromise Proposal. As such, the Department considers the Compromise Proposal in the nature of joint comments. Nevertheless, as reflected in our decision, we recognize the value of a jointly-proposed resolution and constructive approach for many of the issues raised in this docket, submitted by a majority of the active stakeholders in this matter.

IV. DEPARTMENT OBJECTIVES

The Department's key objectives in this investigation include the following. First, the Department seeks to provide ratepayers with the greatest possible benefits from NM and SMART facilities participating in the FCM because ratepayers provide significant subsidies to make those facilities commercially viable. See D.P.U. 17-140-A at 103. Second, the Department strives to maximize the benefits to all ratepayers of ratepayer-subsidized programs, while also carrying out the Commonwealth's energy and environmental policy goals that are within our purview. See Net Metering Rulemaking, D.P.U. 16-64-C at 4 (2016); see also Three-Year Energy Efficiency Plans, D.P.U. 12-100 through D.P.U. 12-111, at 136-137 (2013). Third, the Department favors (1) programs that can provide direct bulk power system benefits, and (2) policies that can minimize ratepayer costs and charges on the bulk power system. See D.P.U. 17-140-A at 99; Long-Term Contracts to Purchase Wind Power, D.P.U. 10-54, at 171-173 (2010); Electric Vehicles, D.P.U. 13-182-A at 14 (2014). Finally, it is the Department's longstanding precedent to consider whether our acceptance of policies or rules will allow or encourage artificial and unfair manipulations of a regulatory system. D.P.U. 17-146-A at 29; Net Metering and Interconnection of Distributed Generation, D.P.U. 11-11-C at 19, 22 (2012); See, e.g., Pricing and Procurement of Default Service, D.T.E. 99-60-B at 5-6, 10 (2000).

In this Order, the Department seeks to establish a fair and efficient process for qualification and participation of NM and SMART facilities in the FCM ("NM/SMART FCM Process"). The Department recognizes that all ratepayers bear the cost of the NM and SMART programs. The Department also acknowledges and seeks to further the Commonwealth's policies to provide renewable and alternative energy for the immediate preservation of the public convenience and to promote the use of ESS throughout the Commonwealth. See An Act Relative to Green Communities, St. 2008, c. 169; An Act to Promote Energy Diversity, St. 2016, c. 188, § 15. As such, in establishing a NM/SMART FCM Process, the Department seeks to balance maximizing direct and indirect benefits to ratepayers with furtherance of the Commonwealth's energy policy goals.

V. OWNERSHIP OF CAPACITY RIGHTS

A. Introduction

In this docket, we investigated who should hold title to the capacity rights associated with NM and SMART facilities. Commenters identified five categories of NM and SMART facilities for which ownership of capacity rights requires clarification: (1) Class I NM Facilities; (2) ESS paired with NM or SMART facilities; (3) existing NM facilities for which a Distribution Company did not assert title and the HC has qualified the facility in the FCA; (4) Qualifying Facilities ("QF") participating in the SMART program; and (5) DG Facilities. We address each category in turn below.

B. Class I NM Facilities

1. Summary of Comments

National Grid notes that Class I NM facilities are not currently registered in the ISO-NE energy market or FCM, but, if appropriate implementation of advanced metering infrastructure occurred, National Grid would seek to register those facilities as SOGs in both markets (National Grid Comments at 2-3, 5 (February 1, 2018)). The majority of commenters argue that the capacity rights associated with Class I NM facilities should reside with the HC and that the Distribution Companies should not have the opportunity to assert title (NECEC Comments at 3 (February 1, 2018); Sunrun Comments at 12-13 (February 1, 2018); Compact Reply Comments at 3 (February 22, 2018); Sunrun Comments at 14 (June 19, 2018); Compact Comments at 10 (July 9, 2018); Attorney General Comments at 6 (July 9, 2018); CPower/EnerNOC Comments at 9 (July 9, 2018)). The Compromise Proposal recommends that its Framework not apply to Class I NM facilities (including Class I NM facilities enrolled in SMART) and that HCs automatically own the rights to both capacity and energy associated with Class I NM facilities (Compromise Proposal at 2).

2. Analysis and Findings

A Class I NM facility is a plant or equipment that is used to produce, manufacture, or otherwise generate electricity that has a design capacity of 60 kW or less and is not a small hydroelectric NM facility participating in the SHP. G.L. c. 164, § 138; 220 CMR 18.02. In creating the NM program, the Legislature limited the administrative burden for and incentivized the development of small, residential solar facilities. G.L. c. 164, §§ 138-140 (e.g., small NM facilities are exempt from applying for a cap allocation).[29] While the Department recognizes National Grid's desire to register Class I NM facilities in the ISO-NE markets if appropriate implementation of advanced metering infrastructure occurred, Class I NM facilities are not currently registered in either market (National Grid Comments at 2, n.5 (February 1, 2018)).

As such, in furtherance of the Legislature's intent, and in concurrence with the majority of stakeholders, the Department finds that the Distribution Companies shall not hold title to the energy and capacity associated with Class I NM facilities, including Class I NM facilities enrolled in the SMART program. The Department directs the Distribution Companies to provide any documents necessary to transfer title to the energy and capacity rights of existing Class I NM facilities to the associated HC within 30 business days of the date of this Order. Moving forward, the Distribution Companies are directed to provide HCs of new Class I NM facilities with any documents necessary to transfer title to the energy and capacity rights associated with Class I NM facility within 15 business days of confirmation that the facility will take service under the NM tariff.

C. Energy Storage Systems Paired with NM or SMART Facilities

1. Introduction

On February 1, 2019, the Department issued an Order in this docket confirming the eligibility of NM facilities paired with an ESS ("paired system") to take service under the NM tariff so long as the paired system is in compliance with one of three approved technical

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[29] A cap exempt facility means a Class I NM facility that is a renewable energy generating facility and has a nameplate capacity rating equal to or less than (1) ten kW on a single-phase circuit or (2) 25 kW on a three-phase circuit. G.L. 164, § 139(i); 220 CMR 18.02.

configurations. D.P.U. 17-146-A at 51. The Department defined ESS for net metering purposes as:

> a commercially available technology that is capable of absorbing energy, storing it for a period of time and thereafter dispatching electricity; provided, however, that an energy storage system shall not be any technology with the ability to produce or generate energy.

The Department further found that the Distribution Companies held title to the energy rights associated with only the NM facility portion of a paired system. The Department has not previously addressed who should own title to the capacity associated with an ESS paired with a NM or SMART facility. D.P.U. 17-146- A at 18-20; D.P.U. 17-140-A at 125-127 (2018) (choosing to address capacity rights in a subsequent proceeding).

2. <u>Summary of Comments</u>

Most stakeholders argue that capacity rights associated with an ESS paired with a NM or SMART facility should reside with the Facility Owner (ViZn Comments at 1 (February 1, 2018); AES Comments at 4 (July 9, 2018); Compact Comments at 2, 9 (July 9, 2018); DOER Comments at 13 (July 9, 2018); Genbright Comments at 3 (July 9, 2018); NECEC Comments at 32 (July 9, 2018); PowerOptions Comments at 4 (July 9, 2018); Tesla Comments at 12 (July 9, 2018)).

Some stakeholders argue that there should be different treatment for certain types of facilities. The Attorney General contends that capacity rights of a BTM solar facility paired with ESS should remain with the Facility Owner, but that capacity rights for FTM facilities paired with ESS should reside with the Distribution Company if it asserts title, or with the Facility Owner if they (1) present a buyout offer or (2) elect to be a load reducer (Attorney General Comments at 12 (July 9, 2018)).

National Grid argues that the capacity rights of a NM and SMART facility should be treated differently. For instance, National Grid suggests that if a facility receives an ESS adder through the SMART Program, capacity rights should reside with the Distribution Company; whereas, for facilities in the NM program and SHP, capacity rights associated with an ESS should reside with the HC (National Grid Comments at 22-23 (July 9, 2018)). Eversource recommends maximizing revenues to offset the NM and SMART programs since ratepayers support the deployment of these resources (Eversource Comments at 12-13 (July 9, 2018)). Eversource, however, also indicates that the Distribution Companies should not be responsible for ESS dispatch or control because it is likely to be costly and challenging (Eversource Comments at 12-13 (July 9, 2018)).

Sunesty argues that the most feasible approach for ESS capacity rights is to have single-party ownership (Sunesty Comments at 3 (July 6, 2018)). Sunesty recommends that the Distribution Companies maintain the ESS capacity rights, but act as an agent and not take on any risk or benefits (Sunesty Comments at 3 (July 6, 2018)).

Several commenters note that it is the Commonwealth's goal to promote cost-effective deployment of ESS and renewable energy (DOER Comments at 13 (July 9, 2018); Companies Reply Comments at 3 (July 25, 2018)); (Compromise Proposal at 1)). DOER also contends that the buyout option will assist in avoiding potential conflicts with existing ISO-NE rules regarding registration of paired assets (e.g., solar paired with ESS) (DOER Reply Comments at 5 (July 25, 2018)).

The Compromise Proposal recommends that the capacity rights associated with an ESS paired with any class of solar NM facility or SMART facility should reside with the Facility Owner (Compromise Proposal at 1-2).

3. Analysis and Findings

The Department acknowledges that the majority of commenters agree that the capacity rights associated with an ESS paired with a NM or SMART facility should reside with the Facility Owner (AES Comments at 4 (July 9, 2018); Compact Comments at 9 (July 9, 2018); DOER comments at 13 (July 9, 2018); Genbright Comments at 3 (July 9, 2018); NECEC Comments at 32 (July 9, 2018); PowerOptions Comments at 4 (July 9, 2018); Tesla Comments at 12 (February 22, 2018); Companies Reply Comments at 5 (July 25, 2018); Compromise Proposal at 1)). The Department finds that allowing a Facility Owner of an ESS paired with a NM or SMART facility to retain title to the capacity rights associated with the ESS is consistent with the Commonwealth's energy policies and goals of cost-effectively promoting ESS and renewable energy deployment. See St. 2016, c. 188, § 15(b); 225 CMR 20.07(4)(c). In addition, the Department finds that a Facility Owner holding title to the capacity rights associated with an ESS paired with a NM or SMART facility (in conjunction with the buyout option discussed in Section VI) could avoid potential conflicts with current ISO-NE rules regarding registration of paired assets (ISO-NE presentation, "Qualification and Participation of Net-Metering Facilities and Energy Storage Systems in the Forward Capacity Market" ("ISO-NE Presentation") (June 4, 2018); DOER Reply Comments at 5 (July 25, 2018); Compromise Proposal at 2). Furthermore, the Department finds that if a Facility Owner holds title to the capacity rights associated with an ESS paired with a NM or SMART facility, it may be more likely to exercise the buyout option discussed in Section VI below and purchase the capacity rights associated with an eligible facility paired with an ESS to make the ESS facility financially viable.[30]

Accordingly, the Department affirms its decision in D.P.U. 17-146-A and finds that the Distribution Companies do not hold title to the energy or capacity rights associated with an ESS that is paired with a NM or SMART facility.[31] While the Department recognizes that the Compromise Proposal limits its recommendation to ESS paired with solar NM or SMART facilities, in light of our decision in D.P.U. 17-146-A, we find it appropriate to apply our decision to ESS paired with any type of NM facility, regardless of technology.

D. Existing NM Facilities Qualified in FCA

1. Summary of Comments

The Compromise Proposal recommends that the Distribution Companies not automatically be granted capacity rights to Class II or III NM facilities that a Distribution Company did not previously assert title to under the NM tariff and that the HC has either (a) successfully qualified in any previous FCA or (b) submitted a Qualification Package in the most recent FCA before the date of this Order (Compromise Proposal at 1-2, 5). NECEC, a Collaborator of the Compromise Proposal, emphasized that it is critical to ensure that capacity rights of existing NM facilities that have successfully qualified for the FCM are unaffected by any change to the NM rules contemplated by the Compromise Proposal (NECEC Reply

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30 As discussed in Section VI, we anticipate that the buyout option will provide revenue to ratepayers.

31 We note that it is the HC of paired system's responsibility to ensure that the NM facility potion of the paired system remains eligible to participate in the ISO-NE energy market. D.P.U. 17-146-A at 18-20.

Comments at 3 (July 25, 2018)). Genbright argues that the Compromise Proposal should not affect the capacity rights of any NM facility for which the Distribution Companies have not previously asserted title under its NM tariff (Genbright Reply Comments at 5-6 (July 25, 2018)).

2. Analysis and Findings

As stated above, an important objective of the Department in this proceeding is to ensure that ratepayers receive the maximum potential direct and indirect benefits available from ISO-NE market revenue streams while maintaining consistency with the Commonwealth's energy policies. Here, the Department agrees with the Collaborators that an existing Class II or III NM facility where a Distribution Company has not previously asserted title under the NM tariff and the HC has either (a) successfully qualified the facility in any previous FCA or (b) submitted a Qualification Package in the most recent FCA before the date of this Order, should receive different treatment with regards to ownership of capacity rights. However, we find that ratepayers should be credited the revenue associated with the capacity of Class II and III NM facilities unless a facility has an existing obligation to ISO-NE. Unless a HC has a CSO or is actively working to obtain a CSO, the Department finds it contrary to our goals in this proceeding to allow a HC to obtain title to the capacity rights associated with a Class II or III NM facility without exercising the buyout option discussed below in Section VI. The Department also finds that it would be contrary to our goals in this proceeding to require a Distribution Company to take on an existing CSO when it did not have an opportunity to evaluate whether obtaining a CSO for that specific facility would be in the best interest of the ratepayers.

As such, to ensure consistency with the Department's objectives, we find that the Distribution Companies do not hold title to the capacity rights associated with a Class II or III NM facility if the Distribution Company has not previously asserted title under the NM tariff and the HC meets either of these conditions: (1) submitted a Qualification Package in the most recent FCA before the date of this Order or (2) qualified and participated in a prior FCA and has an existing CSO.

E. QF SMART Facilities

1. Introduction

The SMART program allows solar tariff generating units that take service under the Distribution Companies' QF tariff, pursuant to 220 C.M.R. 8.00, to receive incentive payments pursuant to the SMART Provision (SMART Model Tariff at 4). The Department's Initial and Revised Straw Proposals specifically exclude QFs participating in the SMART program. The Compromise Proposal does not address QFs.

2. Summary of Comments

The Companies state that the Collaborators did not address QFs because the Department's Revised Straw Proposal did not include QFs (Companies Reply Comments at 6 (July 25, 2018)). The Companies recommend that the Department apply the Framework to QFs within the SMART program and establish appropriate criteria for QFs, as the Department should treat the capacity of all facilities the same (Companies Joint Reply Comments at 6 (July 25, 2018)). The Companies argue that they should have irrevocable right and title to the capacity of QFs that enroll in the SMART program; QF owners enrolled in the SMART program should voluntarily transfer their renewable energy credits ("RECs"), capacity, and other potential future environmental attributes in exchange for SMART incentive payments and be paid for their energy through enrollment in the QF tariff[32] (Companies Joint Reply Comments at 6-7 (July 25, 2018)). The Companies contend that, while QFs may be paid the "avoided costs" of energy and capacity under a QF tariff, significant changes that have occurred in restructured energy markets in New England, including Massachusetts, since the enactment of the Public Utility Regulatory Policies Act of 1978 ("PURPA"),[33] now make the concept of "avoided costs" questionable[34] (Companies Joint Reply Comments at 7 (July 25, 2018)). The Companies also argue that the SMART Provision and competitive request for proposals ("RFP") contained the fundamental assumption that all products, including capacity, will transfer to the Distribution Companies as all facilities that enroll in the SMART tariff will receive the same total compensation regardless of whether they take service under different tariffs with different values of energy (National Grid Comments at 20-21 (July 9, 2018); Companies Joint Reply Comments at 8 (July 25, 2018)).

The Companies argue that if QFs are not required to voluntarily transfer their capacity rights to the Distribution Companies when enrolling under the SMART Provision, QF owners will have the potential to earn double compensation for their capacity revenue stream; this circumstance will create an inequity in the program by enhancing the potential value of

32 For example, Fitchburg Gas and Electric Light Company "Rates Applicable to Qualifying Facilities and On-site Generating Facilities Schedule QF" -- M.D.P.U. No. 257.

33 Pub. L. 95-617; 92 Stat. 3117.

34 National Grid argues that while PURPA requires that QFs be paid the avoided costs of energy and capacity, QFs have no avoided capacity value if the facility has not successfully entered into an FCA and received a CSO for the capacity (National Grid Comments at 20 (July 9, 2018)).

developing a solar project as a QF rather than as an AOBC or NM facility and create a windfall for the QFs (National Grid Comments at 20-21 (July 9, 2018); Companies Reply Comments at 8-9 (July 25, 2018)).

NECEC maintains that the Department should decide the treatment and compensation for QF capacity rights, including any terms and procedures to transfer QF capacity rights to the Distribution Companies, in a QF tariff proceeding, not in this proceeding (NECEC Reply Comments at 9 (July 25, 2018)). NECEC argues that the Companies' assertion that they proposed the SMART program to require that all facilities transfer to the Distribution Companies their rights to all SMART facility attributes including capacity for enrolling in the program is inaccurate as DOER (1) designed the SMART program with input from a range of stakeholders, not just the Distribution Companies; (2) did not include explicit terms that QF capacity should voluntarily be transferred to the Distribution Companies; and (3) intended to structure the SMART program to compensate solar facilities only for Class I RECs and other environmental attributes, not to provide an all-in compensation scheme for energy and capacity and other attributes that will compete directly with other tariffs (NECEC Reply Comments at 10-11 (July 25, 2018)).

NECEC also contends that including QF facilities in the straw proposal would be inconsistent with the Commonwealth's QF Regulations 220 CMR 8.00, which the Department is currently revising in docket <u>Qualifying Facility Rulemaking</u>, D.P.U. 17-54 (NECEC Reply Comments at 11 (July 25, 2018)). NECEC contends that if in D.P.U. 17-54, the Department provides solar and other QF facilities the option to sell their capacity to the Distribution Companies under terms specified in those regulations, the SMART Regulations will explicitly exclude the value of QF capacity from being compensated under SMART; this outcome contradicts the Companies' assertion that the SMART program was designed to compensate QF facilities for capacity rights (NECEC Reply Comments at 11(July 25, 2018)).

NECEC opposes the Companies' argument that by not transferring QF capacity rights to the Distribution Companies QF owners will be paid twice for capacity, because the Distribution Companies added terms to the SMART program 100-megawatt procurement that were not required under SMART Regulations; and the auction was used to establish a rough benchmark for minimum financial viability of large solar projects and not to determine the appropriate compensation level for capacity rights or to prejudge the ownership of SMART facility capacity rights (NECEC Reply Comments at 11 (July 25, 2018)).

3. Analysis and Findings

PURPA and the associated regulations of FERC and the Department establish rules for the sale of generating energy and capacity from QFs to electric companies, such as the Distribution Companies. 92 Stat. 3117, § 210; 16 USC § 824a-3; 18 CFR 292.303, 292.304; 220 CMR 8.05. Distribution Companies' QF tariffs set the terms and conditions for the assignment and treatment of energy and capacity from QFs in their service territories. See Fitchburg Gas and Electric Light Company –Schedule QF M.D.P.U. No. 257; Massachusetts Electric company and Nantucket Electric Company – Rate P M.D.P.U. No. 1321; NSTAR Electric Company– Rate P-2 M.D.P.U. No. 54. The Department has instituted a rulemaking to update its regulations concerning the sale of energy and capacity from QFs to comply with Allco Renewable Energy Ltd. v. Massachusetts Electric Co. et al., 208 F.Supp. 3d 390

(D. Mass. 2016)[35] and 18 CFR 292.304(d). D.P.U. 17-54, at 5 (2017). Treatment of capacity rights associated with QF facilities is within the scope of D.P.U. 17-54. As such, while the Department recognizes persuasive arguments from both NECEC and the Companies, the Department will not address ownership of capacity rights associated with QFs participating in the SMART program in this docket.

F. DG Facilities

1. Introduction

Currently, Distribution Companies have the right to assert title to the capacity associated with Class II and III NM facilities but they are not obligated to participate in the FCM. D.P.U. 09-03-A at 18. A Distribution Company must declare its intent to seek capacity payments when a HC applies for NM services, and the Distribution Company is then obligated to act in a commercially reasonable manner to obtain any such capacity payments, which will be applied to offset any NMRS. D.P.U. 09-03-A at 19.

National Grid is the only Distribution Company to assert title to capacity of NM facilities, although it has not yet enrolled the capacity of any NM facilities in the FCM. D.P.U. 17-140–A at 112. Neither Eversource nor Unitil has asserted title to capacity rights for any net metering facilities. D.P.U. 17-140-A at 112.

2. Summary of Comments

The Attorney General argues that, while the Department should require the Distribution Companies to qualify and bid Class II and III NM facilities into ISO-NE's FCM to fully

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35 Allco Renewable Energy Ltd. v. Massachusetts Electric Co. et al., 875 F. 3d 64 (1st Cir. 2017) (District Court's limiting relief to invalidating the Department's QF regulations upheld).

maximize benefits for the Commonwealth's ratepayers, the Distribution Companies should have some discretion to manage risk and to determine which facilities to bid into the FCM (Attorney General Comments at 3-4 (February 1, 2018)).

Many stakeholders recommend that the Department should not require the Distribution Companies to assert title to the capacity rights of all Class II and III NM facilities and SMART facilities (Cape Light Compact Comments at 9 (February 1, 2018); DOER Comments at 4-6 (February 1, 2018); Sunrun Comments at 24 (February 1, 2018); Tesla Comments at 4 (February 1, 2018); CPower and EnerNOC Comments at 2 (July 25, 2018)). DOER proposes that the Distribution Companies be allowed a prudency review to determine whether the risks and savings to ratepayers warrant asserting title, bidding, and qualifying a NM facility's capacity into ISO-NE's FCM (DOER Comments at 4, 6 (February 1, 2018)). Stakeholders contend that, if the Distribution Companies do not qualify and bid the NM facility into the FCM, title to capacity should either transfer to the Facility Owner or to designated third parties (Cape Light Compact Comments at 4, 9 (February 1, 2018); DOER Comments at 6 (February 1, 2018); Genbright Comments at 7-8 (February 1, 2018); NECEC Comments at 7 (February 1, 2018); PowerOptions Comments at 2 (February 1, 2018); Tesla Comments at 2-4 (February 1, 2018); NECEC Reply Comments at 3, 6 (February 22, 2018)).

The Attorney General argues that, while the Distribution Companies should have the right to the energy and capacity payments from NM and SMART facilities to maximize the benefits for the Commonwealth's ratepayers, thus far, the Distribution Companies have failed to provide any direct benefits such as payments from capacity markets or enable indirect benefits from facilities that act as load reducers (Attorney General Comments at 3-4 (July 9, 2019)).

Some stakeholders maintain that the Distribution Companies should not enroll any NM or SMART facilities they manage as a SOG under Option 1 of the Compromise Proposal, but instead should enroll the facilities as passive demand response, on-peak resources, as ratepayers may be subject to steep PFP penalties if ISO-NE declares a scarcity event and a DG Facility was either not producing or was not exporting to the grid due to load consumption at the facility (Cape Light Compact Reply Comments at 6 (July 25, 2018); CPower/EnerNOC Comments at 7 n.8 (July 9, 2018); NECEC Reply Comments at 5 (July 25, 2018; Tesla Reply Comments at 2-3 (July 25, 2018)).

The Companies assert that it is not in the best interests of their ratepayers to require the Distribution Companies to qualify and bid every NM and SMART facility in the FCM (Eversource Comments at 8 (February 1, 2018); National Grid Comments at 6-9, 12 (February 1, 2018)). Instead, the Companies recommend that they should use their judgment to evaluate each NM facility that they claim capacity to and decide how to monetize that NM facility in the FCM in the best interests of distribution customers (Eversource Comments at 5, 8 (February 1, 2018); National Grid Comments at 6-9,12 (February 1, 2018)). The Companies maintain that it may be more beneficial for ratepayers if the Distribution Companies retain capacity rights and passively earn performance incentive payments under ISO-NE's PFP rule, if capacity scarcity conditions occur coincident with solar production at the facility (Eversource Comments at 5 (February 1, 2018); National Grid Comments at 6-8 (February 1, 2018)). Eversource contends that it has not asserted title to the capacity of any NM facilities as it did not want to take on the risks associated with the performance of these facilities, the conditions of ISO-NE's market rules, and potential performance penalties for facilities that it bid and registered into ISO-NE's FCM (Eversource Comments at 3 (July 9, 2018)). National Grid maintains that, since 2014, it has thoughtfully considered participating in the FCM for those NM facilities for which it has asserted title, including providing a proposal to bid NM capacity into the FCM as part of its base distribution rate case filing in D. P. U. 15-155 (National Grid Reply Comments at 3-4 (February 22, 2018)).

The Compromise Proposal recommends that the capacity rights of DG Facilities automatically transfer to a Distribution Company without a requirement to assert title (Compromise Proposal at 1-2). The Compromise Proposal further recommends that the Distribution Companies be required to monetize the capacity of DG Facilities in one of two ways: (1) directly monetize the capacity by qualifying and bidding that capacity into the FCM to obtain a CSO as Option 1; or (2) register the DG Facility in the FCM to passively earn performance incentive payments under ISO-NE's PFP rule as Option 2 (Compromise Proposal at 3).

NECEC contends that the Compromise Proposal ensures that the Distribution Companies will be required to monetize the capacity for DG Facilities that they take title to for the benefit of ratepayers (NECEC Reply Comments at 3 (July 25, 2018)). National Grid and Eversource recommend that NM facilities that expand to become Class II and III facilities be treated the same as other NM facilities in this proceeding (Companies Reply Comments at 2, n.5 (July 25, 2018)).

3. Analysis and Findings

Since the cost of the NM and SMART programs are borne by all ratepayers, the Department must consider carefully the process to determine ownership of capacity rights associated with DG Facilities, to ensure that the maximum benefit from participation with these facilities in the FCM is recognized by ratepayers. While some commenters recommend that the capacity rights associated with DG Facilities should always reside with the Facility Owner, the overwhelming request from stakeholders, both through comments and at the June 4, 2018 technical conference, is for the Department to establish a process whereby Distribution Companies are required to either participate in the FCM or relinquish title to capacity rights.

Ratepayers will receive the greatest benefit from the participation of DG Facilities in the FCM if they are directly credited the revenue obtained from such participation through the NMRS and SMART Factor. The Department has the authority to regulate the Distribution Companies and, thus, can ensure proceeds from Distribution Company participation with DG Facilities in the FCM are credited directly to ratepayers. As such, the Department finds that it can establish a process that affords ratepayers the maximum benefit from DG Facility participation in the FCM when the capacity rights of DG Facilities automatically transfer to the Distribution Companies without a requirement to assert title. We recognize the Attorney General's concern that, thus far, the Distribution Companies have failed to provide any benefits from the FCM to ratepayers (Attorney General Comments at 3-4 (July 9, 2019)). We also recognize stakeholder concern that requiring the Distribution Companies to participate in the FCM with DG Facilities without allowing some discretion to manage risk could result in participation that is not in the best interests of ratepayers (Attorney General Comments at 3-4 (February 1, 2018); Cape Light Compact Comments at DOER Comments at 6 (February 1, 2018); Eversource Comments at 5, 8 (February 1, 2018); National Grid Comments at 6-9, 12 (February 1, 2018)). Further, stakeholders have expressed a desire for the

NM/SMART FCM Process to include an opportunity for Facility Owners to claim title to the capacity rights associated with a DG Facility if the Facility Owner determines it would be better able to manage the risk and maximize the potential proceeds from participation in the FCM (Cape Light Compact Comments at 7 (February 1, 2018); DOER Comments at 6 (February 1, 2018); Genbright Comments at 7-8 (February 1, 2018); NECEC Comments at 7 (February 1, 2018); Tesla Comments at 4 (February 1, 2018)).

Here, we find that the Compromise Proposal's recommendations to require a Distribution Company to participate in the FCM paired with the buyout option for Facility Owners detailed in Section VI, appropriately addresses stakeholder concerns and Department objectives. In this regard, the Compromise Proposal (1) ensures that a Distribution Company participates in the FCM with DG Facilities; (2) provides a Distribution Company with discretion to determine whether it would be in the best interest of ratepayers to actively or passively participate in the FCM; (3) through the buyout option, addresses stakeholder desire to claim title to capacity rights associated with a DG Facility under certain circumstances (see Section VI); and (4) ensures that ratepayers are directly credited the revenue from DG Facility participation in the FCM to compensate for the cost of the NM and SMART programs, which are borne by all ratepayers.

As such, the Department incorporates the recommendations of the Compromise Proposal in its NM/SMART FCM Process with regard to title to capacity rights associated with DG Facilities. We direct the Distribution Companies to automatically assume title to the capacity rights of DG Facilities and participate with each DG Facility in the FCM either under Option 1 or Option 2 as set forth in the Compromise Proposal.[36] A Distribution Company will only be exempt from the participation requirement for a specific DG Facility if the facility cannot be qualified for the FCM due to circumstances outside of the Distribution Company's control, and the Distribution Company can demonstrate that it made reasonable efforts to mitigate the issues preventing qualification. The Distribution Companies are directed to credit any proceeds obtained through participation with DG facilities in the FCM to ratepayers through the NMRS and SMART Factor, subject to cost recovery requirements of the NM/SMART FCM Process detailed in Section VII below.

Finally, the Department addresses the Companies' recommendation that a Class I NM facility that expands to become a Class II or III NM facility be treated the same as other DG Facilities (Companies Reply Comments at 2, n.5 (July 25, 2018)). In making determinations concerning the NM program rules and regulations, the Department must mitigate manipulation and gaming of the NM program. Here, since the NM/SMART FCM Process grants title to capacity rights associated with Class I NM facilities to the HC and title to capacity rights associated with Class II and III NM facilities to the Distribution Companies, a Facility Owner could manipulate the NM program by enrolling as a Class I NM facility, obtaining title to capacity and then subsequently expanding to become a Class II or III NM facility while retaining title. Therefore, to mitigate potential manipulation of the NM program, we find that it is appropriate to include the Companies' recommendation in the Department's NM/SMART FCM Process. As such, a Distribution Company shall obtain title to capacity rights associated with

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[36] The Distribution Company must participate with the DG Facility in the FCM in the next SOI period.

any Class I NM facility that expands to become a Class II or III NM facility. The Facility Owner shall take the necessary actions for the transfer of title within 30 business days of the expansion. The Department recognizes that this rule will require the Facility Owner to relinquish title to the capacity rights associated with the former Class I NM facility. If a Facility Owner refuses to relinquish title within the required time, the Facility Owner will forfeit its eligibility to participate in the NM program. Facility Owners of Class I NM facilities are now on notice of this requirement and, thus, should make decisions concerning expansion and participation in the ISO-NE markets with the energy and capacity associated with their facility accordingly.

VI. BUYOUT OPTION

A. Buyout Process

1. Introduction

On June 4, 2018, the Department held a technical conference on the qualification and participation of certain NM and SMART facilities in the FCM. At the technical conference, stakeholders discussed the possibility for a Facility Owner to purchase title to capacity rights associated with a NM or SMART facility (a "buyout option"). On June 19, 2018, in response to discussions at the technical conference, the Department issued a Revised Straw Proposal, which included a buyout option (Hearing Office Memorandum, June 19, 2018, Revised FCM Straw Proposal Flow Chart). The Department included a buyout option in its Revised Straw Proposal as a potential means to enhance ratepayer value and to illustrate the inclusion of that option in the proposed FCM process. The Department sought written comments on the terms and process for the buyout option (Hearing Office Memorandum, June 19, 2018). The Collaborators have proposed the terms and process for a buyout option as part of the Compromise Proposal

(Compromise Proposal at 3-5). The buyout option recommended in the Compromise Proposal is comprised of a buyout process and a buyout formula, discussed in turn below.

2. Buyout Process Summary

The Compromise Proposal recommends that the buyout option be available solely to (1) BTM solar DG Facilities, and (2) FTM solar DG Facilities that are paired with ESS (Compromise Proposal at 2-3). The Compromise Proposal recommends that the buyout option be a one-time, up-front purchase of the capacity rights associated with an eligible facility (Compromise Proposal at 3). The buyout option would result in a permanent transfer of capacity rights from a Distribution Company to the Facility Owner (Compromise Proposal at 3-4). The amount paid by the Facility Owner to the Distribution Company for the capacity rights ("buyout price") would be calculated by a fixed formula, discussed below in Section VI.B. (Compromise Proposal at 4).

For new eligible facilities, the buyout option would be available any time after the filing of an interconnection application and before receipt of an ATI (Compromise Proposal at 4-5). Existing eligible facilities would be able to exercise the buyout option at any time unless the Distribution Company either (1) was in the process of qualifying the resource in the FCM (i.e., submitted a Show of Interest) or (2) already had successfully qualified the resource for the FCM for the current qualification period (Compromise Proposal at 5).

The Compromise Proposal characterizes retrofitting as a situation where a Facility Owner adds a co-located ESS to an existing facility (Compromise Proposal at 5). For existing solar DG Facilities that retrofit, the buyout option could be exercised after the initial filing of a revised interconnection application to retrofit the facility with ESS and before a new ATI is issued

(Compromise Proposal at 5). If the Distribution Company has already participated in the FCM under Option 1 for an existing solar DG Facility that retrofits and exercises the buyout option, the Distribution Company would be required to transfer any CSO for that facility to the Facility Owner (Compromise Proposal at 5). Finally, the Compromise Proposal recommends that if a BTM solar DG Facility Owner elects the buyout option, the Distribution Company be required to delist the facility from ISO-NE as a SOG (Compromise Proposal at 5).

3. Summary of Comments

Many stakeholders support a buyout option (Compromise Proposal at 1; PowerOptions Comments at 4 (July 9, 2018); Sunesty Comments at 3 (July 6, 2018)). DOER contends that the Compromise Proposal and, in particular, the buyout option reasonably balances deployment of cost-effective renewable resources and ESS, while also maximizing offset of the NMRS through monetization of capacity associated with DG Facilities (DOER Reply Comments at 3-4 (July 25, 2018)). DOER also contends that the buyout option will assist in avoiding potential conflicts with existing ISO-NE rules regarding registration of paired assets (e.g., solar generation facilities paired with ESS) (DOER Reply Comments at 2, 5 (July 25, 2018)). In addition, DOER maintains that Facility Owners that exercise the buyout option are incentivized to participate in ISO-NE markets, increasing competition and potentially reducing capacity market costs (DOER Reply Comments at 4 (January 25, 2018)). NECEC maintains that the Compromise Proposal, in particular the buyout option, will minimize the amount of complaints the Department may receive, thereby reducing the administrative burden resulting from oversight responsibility (NECEC Comments at 12-13 (July 25, 2018)). Some commenters support the buyout option, but they would prefer to expand its applicability to all NM and SMART facilities (Compact Reply

Comments at 9 (July 25, 2018); CPower/EnerNOC Reply Comments at 1 (July 25, 2018); Genbright Supplemental Reply Comments at 7 (July 31, 2018); NECEC Reply Comments at 3, n.4 (July 25, 2018)).

Although Genbright is supportive of the buyout option, it proposes several modifications (Genbright Supplemental Reply Comments at 7-8 (July 31, 2018)). Genbright argues that the Compromise Proposal (including the buyout option) should apply equally to new and existing Class II and III NM facilities, as well as SMART facilities that are not QFs (Genbright Supplemental Reply Comments at 7 (July 31, 2018)). Second, Genbright recommends that the buyout option remain available for existing facilities to the extent a Distribution Company does not have a CSO for the facility under Option 1 (Genbright Supplemental Reply Comments at 7 (July 31, 2018)). Third, Genbright argues that the Distribution Companies must accept any buyout offer that conforms to the Department's established standards so that the Distribution Companies do not have discretion to reject an offer (Genbright Reply Comments at 6 (July 25,2018)).

4. Analysis and Findings

The Department appreciates the Collaborators' joint submission of a proposed buyout process. The Department first considered a buyout option at the June 4, 2018 technical conference and later included a buyout option in its Revised Straw Proposal (Hearing Officer Memorandum, June 19, 2018). The Department favors inclusion of a buyout option in the NM/SMART FCM Process because it advances the Commonwealth's energy policies, while also appropriately compensating ratepayers, who subsidize the NM and SMART programs. As an initial matter, the Compromise Proposal implies, but does not explicitly state, that the proceeds from a buyout will be credited to ratepayers (DOER Reply Comments at 3-4 (July 25, 2018); Compromise Proposal at 3-4). Any buyout option included in the NM/SMART FCM Process must include a credit to ratepayers of the buyout payment. Thus, in considering the proposed buyout option below, the Department treats the proceeds from all buyouts as a credit to ratepayers through the NMRS and SMART Factor.

As discussed above, we agree with the recommendation in the Compromise Proposal that title to capacity rights associated with DG Facilities should vest automatically with the Distribution Companies and revenues obtained through participation in the FCM should be credited to ratepayers because ratepayers provide substantial subsidies to make NM and SMART facilities financially viable. See D.P.U. 17-140-A, at 103. The Department recognizes, however, that Facility Owners believe they may be capable of obtaining more revenue in the FCM than the Distribution Companies, because Facility Owners are able and willing to take on more risk associated with active participation in the FCM than the Distribution Companies who are charged with acting in the best interest of ratepayers. At the June 4, 2018 technical conference, stakeholders maintained that they would be better able to develop renewable energy facilities if they knew they could both participate in the NM and SMART programs and monetize the capacity associated with their DG Facilities. Furthermore, the Department agrees with DOER that Facility Owners that exercise the buyout option may be more incentivized to participate in the ISO-NE markets, increasing competition and potentially reducing capacity market costs (DOER Reply Comments at 4 (July 25, 2018)).

Accordingly, the Department finds that a buyout option is in the best interest of ratepayers because it will provide a guaranteed value for the capacity associated with an eligible facility, while also avoiding risks related to fluctuation in the FCM and administrative costs associated with the Distribution Company’s participation in the FCM. Therefore, the Department includes a buyout option in its NM/SMART FCM Process and will proceed with a discussion of the terms of the buyout option.

First we consider which types of DG Facilities should be eligible to exercise the buyout option. The Compromise Proposal recommends that the buyout option be available to Facility Owners of (1) BTM solar DG Facilities and (2) FTM solar DG Facilities paired with ESS (Compromise Proposal at 2-3). Several stakeholders request that the buyout option be extended to all DG Facilities, including FTM DG Facilities not paired with ESS (Compact Reply Comments at 9 (July 25, 2018); CPower/EnerNOC Reply Comments at 1 (July 25, 2018); Genbright Supplemental Reply Comments at 7 (July 31, 2018); NECEC Reply Comments at 3, n.4 (July 25, 2018)). The Department finds that allowing BTM solar DG Facilities and FTM solar DG Facilities paired with ESS to exercise the buyout option is appropriate because ratepayers will be compensated through the buyout price for the capacity associated with the facilities and it will further the Commonwealth’s policy of promoting the deployment of renewable energy resources and ESS. The Compromise Proposal’s recommendation that only BTM solar DG Facilities that exercise the buyout option be delisted from ISO-NE as SOGs ensures that energy associated with FTM solar DG Facilities paired with ESS will offset the costs of the NM and SMART programs.

The Department recognizes that excluding FTM DG Facilities not paired with ESS from the buyout option will leave some Facility Owners without an opportunity to obtain title to the capacity rights associated with their facilities. However, we understand that 90 to 95 percent of the NMRS offset stems from FTM resources participation in the ISO-NE energy market.[37] As such, we understand there also may be potential to obtain additional revenue from participating with FTM DG Facilities in the FCM. Without further information, the Department cannot credibly confirm for FTM DG Facilities that the buyout option would adequately compensate ratepayers in an amount equal to or greater than the Distribution Companies' participation in the FCM. As such, at this time, the Department does not find it appropriate to allow all FTM DG Facilities to be eligible for the buyout option. The Department considers that limiting the buyout option to those facilities stipulated in the Compromise Proposal will maximize benefits to ratepayers and adequately promote the deployment of renewable energy and ESS in the Commonwealth.

Nevertheless, the Department will closely monitor overall participation in the buyout option as well as the Distribution Companies' participation in the FCM with FTM DG Facilities. If the Department determines in the future that the buyout option could adequately compensate ratepayers for the monetization of the capacity associated with all FTM DG Facilities, or if the Department finds that the Distribution Companies are not appropriately participating in the FCM with FTM DG Facilities not paired with ESS to maximize benefits for ratepayers, the Department will reconsider eligibility for the buyout option.

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[37] In 2012, Eversource stated that FTM NM generators accounted for 94 percent of the excess generation produced by NM customers. NSTAR Electric Company, D.P.U. 12-116, Exh. DPU 1-7(d)). CPower and EnerNOC conducted an analysis of SREC I and SREC II facilities from publically available data, estimating that 90 percent to 95 percent of the energy revenue applied as the NMRS offset is attributed to standalone FTM solar facilities (Cpower and Enernoc Comments at 3, n.2 (July 9, 2018)).

Next, we consider the eligibility of existing facilities to exercise the buyout option. The Compromise Proposal recommends that existing eligible facilities be allowed to exercise the buyout option at any time so long as the Distribution Company is not in the process of qualifying the resource in the FCM (i.e., submitted a Show of Interest) or has not already qualified the resource in the FCM for the current qualification period (Compromise Proposal at 5). Genbright requests that the Department allow all existing NM or SMART facilities to be eligible for the buyout option to the extent that the Distribution Company does not already have a CSO for the facility under Option 1 (Genbright Supplemental Reply Comments at 7 (July 31, 2018)). The Compromise Proposal recommends allowing any existing solar DG Facility that retrofits to add co-located ESS to exercise the buyout option (i) after the initial filing of a revised interconnection application to retrofit, and (ii) before a new ATI is issued (Compromise Proposal at 4-5).

In determining eligibility for the buyout option for existing facilities, the Department seeks to implement efficiency in the NM/SMART FCM Process and to avoid unnecessary complexities that could exist if a facility has already been qualified in the FCM. As such, the Department agrees with the Collaborators that qualification is an appropriate marker for eligibility. The Department finds, however, that allowing solar DG Facilities that choose to add co-located ESS to exercise the buyout option whenever they choose to retrofit is an appropriate exception because it is consistent with the Commonwealth's objective of cost effectively deploying ESS (Compromise Proposal at 2-4). Therefore, existing eligible facilities are allowed to exercise the buyout option at any time so long as the Distribution Company (a) is not in the process of qualifying the resource in the FCM (i.e., submitted a Show of Interest) or (b) has not already qualified the resource in the FCM for the current qualification period; and an existing solar DG Facility that retrofits is allowed to exercise the buyout option (i) after the initial filing of a revised interconnection application to retrofit and (ii) before a new ATI is issued.

B. Buyout Formula

1. Introduction

The Compromise Proposal recommends that the buyout option be a one-time, up-front purchase of capacity rights and that the purchase price be determined by a formula used to calculate the value of capacity over time ("buyout formula") (Compromise Proposal at 2-4). Such a purchase would render a permanent transfer of capacity rights from the Distribution Company to the Facility Owner (Compromise Proposal at 3-4). The Compromise Proposal suggests that the buyout formula is meant to estimate potential long-term FCM revenues for an intermittent resource that a Distribution Company could have received if it had retained capacity rights and participated in the FCM (Compromise Proposal at 4; DOER Reply Comments at 4 (July 25, 2018 at 4)).

2. Buyout Formula Summary

The buyout formula attempts to estimate the future value of capacity associated with an eligible facility. The buyout price is the net present value over 20 years of expected annual cash flows using a ten-percent discount rate (Compromise Proposal at 4).[38] The Compromise Proposal estimates that for a 1-MW eligible facility the buyout price would be approximately $20,711 (Compromise Proposal, Appendix). The buyout formula uses multiple

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[38] A ten-percent discount rate is meant to account for risk of FCM participation and the upfront purchase of the capacity rights (Compromise Proposal at 4).

assumptions and inputs to determine a buyout price for each MW of solar alternating capacity ("AC") nameplate capacity (Compromise Proposal at 4). The annual cash flow is calculated as follows:

Annual Cash Flow = (facility AC nameplate)
* (31.8% capacity contribution)
* (60% of AESC levelized 15 year forecast)
* (80% of revenue share from projected FCM revenues)
* (4 months of yearly solar eligibility in capacity market)
- (Distribution Company FCM administrative costs[39])

The buyout price is calculated as follows:

Buyout Price = Net Present Value (10% discount rate) of up to 20 years of Annual Cash Flows

We discuss the pertinent inputs and assumptions. First, the Compromise Proposal uses a 31.8 percent capacity contribution rate for each kW AC of an eligible facility's nameplate capacity. The Compromise Proposal uses the ten-year average capacity contribution rate derived from the annual capacity contribution rates stated in the ISO-NE 2018 Report of Capacity, Energy, Loads, and Transmission ("CELT Report"). The CELT Report is used in electric planning and operations reliability studies for the ISO-NE region and is conducted annually.[40]

Second, the buyout formula uses the forecasted long-term capacity prices contained in the 2018 Avoided Energy Supply Component ("AESC 2018") study which is conducted every three

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39 Annual escalation of two percent to account for inflation (Compromise Proposal at 4).

40 ISO-NE 2018 CELT Report, https://www.iso-ne.com/system-planning/system-plans-studies/celt/ (last visited January 31, 2019).

years (Compromise Proposal at 4).[41] AESC 2018 attempts to project marginal energy supply components that can be avoided in future years due to reductions in the use of electricity, natural gas, and other fuels as a result of program-based conservation measures across the New England region.[42] In particular, the initial capacity price used in the buyout formula is the average of 15 years of forecasted capacity prices (FCA 9 thru FCA 23), which is currently $6,420/MW-month (Compromise Proposal at 4).[43] The buyout formula further reduces the forecasted capacity price of $6,420/MW-month by 40 percent, and the resulting capacity value is $3,852/MW-month (Compromise Proposal at 4). The Compromise Proposal also proposes that the forecasted capacity price used in the buyout formula be updated every three years (Compromise Proposal at 4).

Third, the buyout formula uses the same revenue share percentage (80 percent) that would be credited to ratepayers had the Distribution Companies retained capacity rights (Compromise Proposal 3-4). Fourth, the buyout formula accounts for the number of months that the facility is eligible to participate in the FCM, which is currently four months. ISO-NE

41 Synapse Economics, Inc., Resource Insight, Les Deman Consulting, North Side Energy, and Sustainable Energy Advantage prepared AESC 2018 as sponsored by electric and gas utilities and energy efficiency program administrators (AESC 2018, at 2). A study group, which included the sponsors and representatives from state government, consumer advocacy organizations, and environmental advocacy organizations and their consultants, oversaw the design and analysis of AESC 2018 (AESC 2018, at 2).

42 2018 AESC Study at 1, http://www.synapse-energy.com/sites/default/files/AESC-2018-17-080.pdf (last visited January 31, 2019) ("2018 AESC Study").

43 The forecasted capacity prices in the 2018 AESC study are the result of actual and forecast clearing prices in the ISO-NE FCM. The forecasted capacity prices are based on experience in recent FCAs and expected changes in demand, supply, and market rules (2018 AESC Study at 95).

assumes in its modeling that any intermittent resource's (e.g., solar) qualified capacity in the FCM is only equal to its summer qualified capacity, therefore, such resources may only be compensated for four months of capacity contribution.[44]

Fifth, the buyout formula offsets (reduces) the buyout price by the estimated long-term Distribution Company administrative costs of $1,300/MW, which reduces the buyout price by this amount for each MW of AC nameplate capacity (Compromise Proposal at 4). The Department's understanding is that these costs are meant to replicate the administrative costs that the Distribution Company would incur had it qualified and registered the facility in the FCM (Compromise Proposal at 4). For any buyout offer, after the initial year, the administrative costs assumption increases by two percent each year to account for inflation (Compromise Proposal at 4).

3. Summary of Comments

Stakeholders generally support the Compromise Proposal's recommended buyout formula. DOER argues that the buyout formula is appropriate because it intends to estimate the amount of capacity revenue the Distribution Company could have received if the Distribution Company had retained title and participated in the FCM (DOER Reply Comments at 4 (July 25, 2018)). Genbright, however, who was not a signatory to the Compromise Proposal, argues that the buyout price for an existing facility should be based on the facility's remaining term of eligibility under the NM or SMART tariff (Genbright Supplemental Reply Comments

44 See ISO-NE Market Rules for FCM, https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_sec_13_14.pdf (last visited January 31, 2019); ISO-NE Glossary of Acronyms, https://www.iso-ne.com/participate/support/glossary-acronyms/ (last visited January 31, 2019).

at 8 (July 31, 2018)). Sunesty argues that if the SMART Program ESS adder is insufficient to incentivize development of ESS, and FCM revenue is required to make ESS viable, then the buyout price should be discounted (or set to zero, if necessary) to assure progress toward meeting the Commonwealth's energy goals (Sunesty Comments at 3, n.3 (July 6, 2018)).

The Attorney General is supportive of the buyout option, but she provides several recommendations regarding future evaluation and adjustments (Attorney General Reply Comments at 3 (July 25, 2018)). First, the Attorney General recommends that the Department conduct a review of the revenues generated from the buyout option (Attorney General Reply Comments at 3 (July 25, 2018)). Second, the Attorney General suggests that the Department consider making adjustments to the buyout terms after considering the total revenues provided from each source (on a per-MW basis) and the participation rate of SMART facilities (Attorney General Reply Comments at 3 (July 25, 2018)). For instance, the Attorney General suggests that if the Departments finds that the revenue per-MW from buyouts is lower than the Distribution Companies' participation in the FCM, or the buyout option is implemented rapidly, it may suggest that the buyout price is too low and that the Department should require an associated adjustment to the buyout formula (Attorney General Reply Comments at 3 (July 25, 2018)).[45] DOER suggests that the Department direct the Distribution Companies to submit an annual informational filing related to FCM participation and the buyout option (DOER Comments at 8-9 (July 9, 2018)).

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45 For example, the Attorney General recommends that the Department could reduce the discount rate or increase the assumed share of the forecasted capacity revenue (Attorney General Reply Comments at 3 (July 25, 2018).

4. Analysis and Findings

The Department appreciates the thoughtful and comprehensive recommendation of the buyout formula. In assessing the reasonableness and accuracy of the buyout formula, we take into consideration the cumulative experience and knowledge of the Collaborators. In general, the Department agrees, based on available information, that the buyout formula includes reasonable assumptions to calculate a value for the capacity associated with eligible facilities that is equal to or greater than the proceeds that could be obtained by the Distribution Companies' direct participation in the FCM. The Department recognizes, however, that some information is presently unavailable to confirm certain assumptions and agrees with the Attorney General and DOER that continued review is appropriate.

The Department also agrees with Genbright that the term length used in the buyout formula requires clarification (Genbright Supplemental Reply Comments at 8 (July 31, 2018)). The SMART Provision limits participation in the SMART program to 20 years. See Fitchburg Gas and Electric Light Company – M.D.P.U. No. 325, § 10.0; Massachusetts Electric Company and Nantucket Electric Company – M.D.P.U. No. 1368, § 10.0; NSTAR Electric Company – M.D.P.U. No. 74, § 10.0. As such, we recognize that existing facilities participating in the SMART program that choose to exercise the buyout option may have a remaining term under the SMART Provision that is less than 20 years. The NM tariff does not set a term limit for participation in the NM program. Consequently, the Department clarifies that (1) for eligible facilities participating only in the SMART program, the term length used to calculate the buyout price will be 20 years less the amount of time the facility has taken service under the SMART Provision, and (2) for eligible facilities participating in the NM program or in both the NM and

SMART programs, the term length used to calculate the buyout price will be 20 years, since no term limit exists for participation in the NM program. The Department finds that using these inputs will allow the Distribution Companies known and measurable timeframes for calculating a buyout price.

Finally, the Department agrees with the Attorney General and DOER that ratepayers would be well served by continued evaluation of the buyout option (Attorney General Reply Comments at 3 (July 25, 2018); DOER Comments at 8-9 (July 9, 2018)). As such, the Department directs each Distribution Company to submit an informational filing as part of its annual NMRS and SMART Factor filings that provides the following information:[46]

(1) The buyout payment received for each facility that exercises the buyout option, including a dollars-per-MW analysis.

(2) The total number of facilities that exercise the buyout option categorized by facility type;[47] also provide this information as MW by facility type.

(3) The total number of DG Facilities that the Distribution Company participates with in the FCM under Option 1; also provide this information as MW by facility type.

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46 While the Department will not require the Distribution Companies to file all of the information recommended by the Attorney General and DOER, the Distribution Companies are put on notice that the Department will request additional information as necessary in the future for proper evaluation of the effectiveness of the NM/SMART FCM Process (Attorney General Reply Comments at 3 (July 25, 2018); (DOER Comments at 8-9 (July 9, 2018)).

47 For the purposes of the informational filings, facility type should include the following: (1) facility technology; (2) whether the facility participates in the NM or SMART program or both; (3) whether the facility is BTM or FTM; and (4) whether the facility is co-located with ESS.

(4) The net proceeds obtained for each DG Facility the Distribution Company participates with in the FCM under Option 1, including a dollars-per-MW analysis.

(5) The total number of DG Facilities that the Distribution Company participates with in the FCM under Option 2; also provide this information as MW by facility type.

(6) The proceeds obtained for each DG Facility the Distribution Company participates with in the FCM under Option 2, including a dollars-per-MW analysis.

(7) Administrative costs that the Distribution Company seeks recovery of for actual participation in the FCM with DG Facilities, by facility and by participation Option.

The Department also directs each Distribution Companies to make certain adjustments to the buyout formula as new information becomes available. First, the Distribution Company should update the buyout formula's AESC long-term forecasted average capacity price in the same year a new final report is issued. Second, the Distribution Company should adjust the 31.8-percent contribution rate used in the buyout formula in each year a new CELT Report is issued.[48] Finally, if actual administrative costs differ significantly from those included in the buyout formula, the Distribution Companies shall petition the Department for a revision to the buyout formula to more accurately reflect actual administrative costs.

C. Conclusion

The Department finds that a buyout option is in the best interest of ratepayers and the Commonwealth and we incorporate a buyout option into the NM/SMART FCM process as follows. Each Distribution Company is directed to accept one-time payments from Facility Owners of eligible facilities that make a written request to purchase the capacity rights associated

[48] The Distribution Companies should confer in making these two potential adjustments.

with an eligible facility. The payment shall be calculated based on the buyout formula (as modified above) and shall result in a permanent transfer of capacity rights from the Distribution Company to the Facility Owner. All proceeds obtained through the buyout option shall be credited to ratepayers through the NMRS and SMART Factor. Each Distribution Company must accept buyout offers from the following: (1) new eligible facilities any time after the filing of an interconnection application and before the new eligible facility receives an ATI; (2) existing eligible facilities at any time unless the Distribution Company is in the process of qualifying the resource in the FCM (i.e., submitted a Show of Interest) or has already successfully qualified the resource for the FCM for the current qualification period; and (3) existing solar DG Facilities that retrofit by adding a co-located ESS, from the time the Facility Owner submits a revised interconnection application until a new ATI is issued. A Facility Owner that elects the buyout option must make payment to the associated Distribution Company not later than 15 business days after written notice of intent to exercise the buyout option is submitted to the Distribution Company. Once the Distribution Company receives the full buyout payment, it must provide the Facility Owner with all necessary documents to transfer title to capacity rights within 15 business days. If the Distribution Company has exercised Option 1 for an existing solar DG Facility that retrofits and exercises the buyout option, the Distribution Company will transfer any CSO it has obtained for that facility to the Facility Owner. The Distribution Companies must delist any BTM eligible facility that exercises the buyout option if it was previously registered as an SOG with ISO-NE. If an existing solar DG Facility that retrofits exercises the buyout option and the Distribution Company has already participated with the facility in the FCM under Option 1, the

Distribution Company shall transfer any existing CSO for that facility to the Facility Owner upon receipt of payment for the buyout.

VII. REVENUE/COST SHARE

A. Introduction

As discussed above, the Department has established a NM/SMART FCM Process whereby the Distribution Companies are required to participate in the FCM with DG Facilities and process buyout option requests for eligible facilities (see Sections V.F and VI). In this section, we discuss the ratemaking treatment of the NM/SMART FCM Process. Specifically, we discuss how the Distribution Companies will recover administrative costs associated with participating in the FCM with DG Facilities and processing buyout option requests, and whether it is beneficial for ratepayers to give the Distribution Companies an incentive to encourage optimal participation in the FCM.

1. Administrative Costs

a. Summary of Comments

National Grid and Eversource argued in favor of recovery of Distribution Company administrative costs associated with participation in the FCM through the NMRS and SMART Factor (National Grid Comments at 10 (February 1, 2018); Eversource Comments at 7 (February 1, 2018)). While several commenters initially maintained that it would not be appropriate for the Distribution Companies to collect a fee or margin to manage the risk associated with its FCM obligations (DOER Comments at 6 (February 1, 2018); Genbright Comments at 6 (February 1, 2018); NECEC Comments at 7 (February 1, 2018); SunRun Comments at 23 (February 1, 2018); Tesla Comments at 4 (February 1, 2018)), in the

Compromise Proposal, the Collaborators propose that all administrative costs associated with participating in the FCM with DG Facilities and processing buyout requests be recovered through the NMRS and SMART Factor (Compromise Proposal at 3).

b. Analysis and Findings

We recognize that requiring the Distribution Companies to participate with DG Facilities in the FCM and process buyout requests creates new administrative burdens. Consequently, complying with this Order may require additional time from current Distribution Company employees or additional staff and resources to effectively administer the NM/SMART FCM Process. The Compromise Proposal suggests that Distribution Company anticipated administrative costs for participating with DG Facilities in the FCM are approximately $1,300 per-MW per-year (see Section VI.B) (Compromise Proposal at 4). This estimated amount is less than National Grid's initial proposal in D.P.U. 15-155.[49] Furthermore, annual per MW revenues received from the participation of utility-owned solar in the FCM appear significantly larger than $1,300 per MW per year, indicating that, on balance, ratepayers will receive a substantial benefit from Distribution Company participation with DG Facilities in the FCM, even after the Distribution Companies recover administrative costs.[50]

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49 In D.P.U. 15-155, National Grid estimated that administrative costs would be approximately $170,000 per full time employee, and that up to four employees may be necessary to manage a portfolio of 375 MW (i.e., approximately $1,813 per MW). D.P.U. 15-155, Exh. NG-SN-9, at 1.

50 In Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid (Solar Cost Adjustment Factors), D.P.U. 17-28, National Grid reported collecting $28,158 in 2016 by bidding its Solar Phase I facilities into the FCM (Exh. NG-3, at 1). National Grid has 4.6 MW of Solar Phase I facilities, resulting in average annual FCM proceeds per MW of $6,000 per MW (Exh. NG-3, at 1).

Therefore, the Department finds it reasonable for the Distribution Companies to recover administrative expenses associated with the NM/SMART FCM Process provided that the Distribution Companies demonstrate that all administrative expenses proposed for recovery are (1) incremental to the representative level of associated O&M expenses recovered through base distribution rates and (2) solely attributable to participation in the FCM with DG Facilities or processing of buyout option requests. D.P.U. 17-140-A at 146; Grid Modernization, D.P.U. 15-120/D.P.U. 15-121/ D.P.U. 15-122, at 222 (2018). The Distribution Companies may seek recovery of these administrative costs through the NMRS and SMART Factor.[51]

2. Distribution Company Incentive Mechanism

a. Summary of Comments

In the first round of comments, the majority of commenters were hesitant to provide the Distribution Companies with an incentive to encourage participation in the FCM (DOER Comments at 6 (February 1, 2018); Genbright Comments at 6 (February 1, 2018); NECEC Comments at 7 (February 1, 2018); Cape Light Comment at 8 (February 22, 2018); Sunrun Comments at 23 (February 1, 2018); Tesla Comments at 4 (February 1, 2018)). Specifically, commenters were concerned that such an incentive would create an uncompetitive advantage in the FCM (DOER Comments at 6 (February 1, 2018); NECEC Comments at 7 (February 1, 2018); Cape Light Comment at 8 (February 22, 2018); Sunrun Comments at 23 (February 1, 2018); Tesla Comments at 4 (February 1, 2018)). Some stakeholders argued that

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51 In D.P.U. 17-140-A the Department established a test for recovery of administrative costs associated with the SMART program. In accordance, the Distribution Companies must meet all requirements set forth in D.P.U. 17-140-A for the recovery of administrative costs associated with the SMART program, including those related to the NM/SMART FCM Process. D.P.U. 17-140-A at 146-152.

the Distribution Companies were not necessarily the best market participants (Genbright Comments at 6 (February 1, 2018); NECEC Comments at 7 (February 1, 2018); Cape Light Comment at 8 (February 22, 2018)). Eversource showed reluctance to implement any incentive mechanism that could result in the Distribution Companies receiving penalties (Eversource Comments at 7-8 (July 9, 2018)).

As the proceeding continued, however, many commenters decided that an incentive in the form of sharing FCM net proceeds between the ratepayers and the Distribution Companies could help to maximize the direct and indirect benefits to ratepayers from participation in the FCM with DG Facilities (DOER Comments at 7 (July 9, 2018); Genbright Comments at 2 (July 9, 2018); NECEC Comments at 9 (July 9, 2018); Sunrun Comments at 7 (July 9, 2018)). Commenters argued for revenue/risk shares as high as 50/50, to promote aggressive market participation (NECEC Comments at 9 (July 9, 2018); PowerOptions Comment at 3 (July 9, 2018)).

The Compromise Proposal recommends sharing the net proceeds[52] between the ratepayers and the Distribution Companies when a Distribution Company actively participates in the FCM with a DG Facility (i.e., participating as Option 1) (Compromise Proposal at 3). Under this proposal, the Distribution Company would retain 20 percent of all net proceeds from participation in the FCM and 80 percent of net proceeds would be credited to ratepayers through the NMRS and SMART Factor (Compromise Proposal at 3). This incentive, however, would not apply to passive participation in the FCM (i.e., participating as Option 2)

52 For the purposes of the Compromise Proposal and this Order, "net proceeds" means the revenue less penalties associated with participation in the FCM (Compromise Proposal at 3).

(Compromise Proposal at 3). If a Distribution Company participates in the FCM with a DG Facility under Option 2, 100 percent of the proceeds would be credited to ratepayers through the NMRS and SMART Factor (Compromise Proposal at 3).

b. Analysis and Findings

The Department will include an incentive mechanism in the NM/SMART FCM Process only if the incentive mechanism will serve to maximize benefits to ratepayers from participation in the FCM with DG Facilities. The incentive mechanism proposed is a percentage share between the Distribution Companies and ratepayers of the net proceeds obtained through participation in the FCM with DG Facilities (DOER Comments at 7 (July 9, 2018); Genbright Comments at 2 (July 9, 2018); NECEC Comments at 9 (July 9, 2018); Sunrun Comments at 7 (July 9, 2018); Compromise Proposal at 3).

First, the Department considers whether this incentive mechanism would maximize proceeds obtained through Distribution Company participation in the FCM with DG Facilities. Pursuant to the NM/SMART FCM Process established in this Order, the Distribution Companies must participate with DG Facilities in the FCM through either (1) directly monetizing the capacity by qualifying and bidding that capacity into the FCM to obtain a CSO as Option 1 or (2) registering the DG Facility in the FCM to passively earn performance incentive payments under ISO-NE's PFP rule as Option 2. The Department understands that obtaining a CSO in the FCM could have higher direct benefits for ratepayers than participating passively under Option 2 (National Grid Comments at 7-8 (February 1, 2018); Eversource Comments at 2-3 (February 22, 2018)). The Department acknowledges, however, that active participation in the FCM involves a level of risk that does not exist in passive participation because it could result in penalties for underperformance (Cape Light Compact Reply Comments at 6 (July 25, 2018); CPower/EnerNOC Comments at 7, fn.8 (July 9, 2018); NECEC Reply Comments at 5 (July 25, 2018); Tesla Reply Comments at 3 (July 25, 2018)). This risk, as well as administrative complexities, have historically deterred Distribution Companies from participating in the FCM with NM Facilities (Eversource Comments at 2 (February 22, 2018); National Grid Comments at 3 (February 22, 2018)). D.P.U. 09-03-A at 19. Here, we seek to incentivize the Distribution Companies to actively participate in the FCM only to the extent that they find it likely that the potential for revenue outweighs the inherent risk in active participation.

Since passive participation under Option 2 of the Compromise Proposal does not involve a risk of penalties,[53] the Department finds it appropriate that all revenues obtained through the Distribution Companies' participation under Option 2 be credited to ratepayers. The Department recognizes, however, that since participating in the FCM under Option 2 does not involve risk and is less administratively burdensome, the Distribution Companies may be more likely to elect Option 2, even if Option 1 has the higher potential to maximize FCM proceeds. As such, the Department agrees with the majority of commenters that an incentive in the form of sharing FCM net proceeds between the Distribution Companies and the ratepayers could help to maximize proceeds obtained from the FCM (DOER Comments at 7 (July 9, 2018); Genbright Comments at 2 (July 9, 2018); NECEC Comments at 9 (July 9, 2018); Sunrun Comments at 7 (July 9, 2018)). Furthermore, the incentive mechanism in the Compromise Proposal, in the form

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53 The Department further acknowledges that the potential for revenue under Option 2 is likely less than under Option 1 (National Grid Comments at 7-8 (February 1, 2018); Eversource Comments at 2-3 (February 22, 2018)).

of shared revenues and penalties obtained in the FCM, is desirable because it both incentivizes active participation when the benefits of such participation outweigh the risks, and disincentives active participation if the risk is high and would likely result in a cost to ratepayers.

With our determination that the proposed incentive mechanism would be effective in maximizing benefits to ratepayers from Distribution Company participation in the FCM, we discuss the advantages and disadvantages of various percentage shares between ratepayers and the Distribution Companies. With respect to promoting market efficiency, stakeholders have argued for a share as high as 50/50, claiming that would promote aggressive market participation (NECEC Comments at 9 (July 9, 2018); PowerOptions Comment at 3 (July 9, 2018)). The Department understands that aggressive market participation would benefit ratepayers by (1) increasing the total net proceeds received in the FCM and (2) lowering regional capacity costs, which will indirectly reduce energy prices. However, we do not currently have sufficient information to fully analyze the tradeoff between the benefits to ratepayers resulting from aggressive participation in the FCM and the benefits to ratepayers from increasing the percentage of net proceeds credited to ratepayers through the NMRS and SMART Factor.[54]

Based on the information available in the record, the Department finds that the 80/20 share recommended in the Compromise Proposal represents an appropriate balance between participation and risk that will ensure maximum benefits for ratepayers. The

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[54] In Rhode Island, ratepayers and National Grid share net proceeds 90/10. Narragansett Electric Company d/b/a National Grid Order No. 23289, at 13 (October 4, 2018). However, that sharing has reduced relevance because material differences exist between the amount of solar, the number of electric distribution companies, and the location with respect to ISO-NE load zones in Rhode Island relative to Massachusetts.

Distribution Companies are, therefore, directed to credit to ratepayers through the NMRS and SMART Factor (1) 80 percent of net proceeds obtained through participation with DG Facilities in the FCM under Option 1 and (2) 100 percent of the proceeds obtained through participation with DG Facilities in the FCM under Option 2. The Distribution will retain 20 percent of net proceeds obtained through participation with DG Facilities in the FCM under Option 1. The Department will closely monitor the net proceeds obtained from each Distribution Company's participation with DG Facilities in the FCM to ensure this incentive mechanism maximizes benefits to ratepayers.[55]

VIII. LOAD REDUCER

A. Introduction

Eight of the ten Collaborators recommend a load reducer option as a separate agreement appended to the Compromise Proposal (Compromise Proposal at 6).[56] The load reducer option Collaborators recommend that HCs of BTM NM facilities[57] be given the opportunity to elect to be load reducers as defined by ISO-NE[58] and not enroll in any ISO-NE market (Compromise Proposal at 6; Attorney General Comments at 8 (July 9, 2018)).

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55 In Section VI.B, the Department directed the Distribution Companies to file information in the annual NMRS and SMART Factor filings sufficient for the Department to monitor net proceeds from each Distribution Company's participation in the FCM.

56 The stakeholders to the load reducer option include the Attorney General, Borrego Solar, DOER, EnerNOC, Engie Storage, NECEC, Sunrun, and Tesla (Compromise Proposal at 1, 6; DOER Reply Comments at 1-3 (July 25, 2018)).

57 The load reducer option would apply to all BTM NM facilities regardless of whether they are paired with ESS (Compromise Proposal at 6).

58 ISO-NE's Operating Procedure No. 14 allows any generating facility with a nameplate capacity between one to five megawatts to operate as a load reducer in the region as long as the facility does not participate in any ISO-NE markets (AG Comments at 8-10

The load reducer option Collaborators recommend that the Department establish the following rules for a load reducer option in the NM/SMART FCM Process: (1) provide HCs of BTM NM facilities the option to elect to operate a new BTM NM facility as a load reducer any time before it is given its ATI (therefore, a Distribution Company would not be able to participate in the FCM with a BTM NM facility until after the facility received an ATI); (2) allow existing BTM NM Facilities to elect to operate as a load reducer; (3) require the Distribution Companies to modify the requirement in the NM tariffs to register all Class II and III NM facilities as SOGs in the ISO-NE energy market to enable the Distribution Companies to withdraw an existing BTM NM facility as a SOG from the ISO-NE energy market within 30 days of a HC's electing to operate as a load reducer; and (4) allow the Distribution Companies to retain control of both the energy and capacity of a BTM NM facility only if a HC does not buyout the capacity rights or elect to be a load reducer (Compromise Proposal at 6). The load reducer section of the Compromise Proposal implies that a HC that elects to be a load reducer would be allowed to participate in the ISO-NE demand response ("DR") program (Compromise Proposal at 6).

B. Summary of Comments

The Attorney General contends that under certain circumstances, the load reducer option may be more beneficial to ratepayers than other options available for participating in the FCM that generate revenues to directly offset the NMRS and SMART Factor (Attorney General Reply

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(July 9, 2018)). ISO New England Operating Procedure No. 14 – Technical Requirements for Generators, Demand Response Resources, Asset Related Demands and Alternative Technology Regulation Resources, December 11, 2017, § II.A.2.

Comments at 2 (July 25, 2018)).[59] While the load reducer option will not produce any direct revenue to offset the NMRS and SMART Factor, the Attorney General asserts that this option would create avoided capacity and transmission benefits for ratepayers by reducing the Installed Capacity Requirement ("ICR") [60] for the FCM and the overall Regional Network Load ("RNL") [61] that is used to calculate Regional Network Service transmission charges[62] (Attorney General Reply Comments at 2 (July 25, 2018)). The Attorney General maintains that, in certain cases, indirect benefits may outweigh unrealized benefits from NM or SMART facilities that either fail to deliver FCM benefits due to the complexities of CASPR or are never built due to the added costs of complying with capacity rules (Attorney General Comments at 9 (July 9, 2018)).

Tesla argues that the load reducer option may result over time in higher ratepayer value than could be achieved from participating in wholesale markets as the capacity market may

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59 The Attorney General contends that the Department should require the Distribution Companies to track and monitor the indirect ratepayer benefits from avoided capacity and transmission costs generated from NM facilities that elect the load reducer option (Attorney General Reply Comments at 3 (July 25, 2018)).

60 The ICR as defined by ISO-NE is a measure of the installed capacity resources that are projected to meet projected demand (i.e., the capacity necessary to meet reliability standards in light of total forecasted electric load requirements for New England and to maintain sufficient reserve capacity to meet reliability standards). D.P.U. 15-155, at 2; D.P.U. 12-77, at 5, citing ISO Tariff, § III.12.

61 RNL defined by ISO-NE as the load that a Network Customer designated for Regional Network Service under Part II.B of ISO-NE's Open Access Transmission Tariff. ISO Tariff, §§ I.1.2, I.2.2.

62 As the load reducer option may not generate revenues to directly offset the NMRS and SMART Factor, the Attorney General suggests that it is essential to verify that benefits are realized elsewhere on customers' bills and to track those benefits (Attorney General Reply Comments at 2 (July 25, 2018)).

either lose its current value or not exist in the future (Tesla Reply Comments at 2-3 (July 25, 2018)).

Stakeholders recommend that the Department modify the Distribution Companies' NM tariffs to remove the requirement that Distribution Companies enroll Class II and III BTM solar NM facilities as an SOG in the ISO-NE energy market because ratepayers will realize more benefits if such facilities instead elect to become load reducers or participate in the buyout option (Attorney General Reply Comments at 2-3 (July 25, 2018); CPower and EnerNOC Reply Comments at 1-2 (July 25, 2018); DOER Reply Comments at 5-6 (July 25, 2018); NECEC Reply Comments at 4-9 (July 25, 2018); PowerOptions Comments at 3 (July 9, 2018); Tesla Comments at 3, 11 (July 9, 2018)). Stakeholders rely on the following as support for this assertion: (1) Eversource's petition to the Department in docket D.P.U. 12-116 to not enroll BTM solar NM facilities as an SOG in the ISO-NE energy market[63]; (2) an AESC Study that estimates between $59,000/MW per year to $109,000/MW per year[64] in potential DR ratepayer benefits; and (3) no meaningful change in the NMRS offset to ratepayers will result as 90 to 95 percent of the NMRS offset stems from FTM resources not covered under the load reducer option or subject to the Compromise Proposal (Attorney General Comments at 9-10, (July 9, 2018); Attorney General Reply Comments at 3 (July 25, 2018); CPower/EnerNOC Comments at 7 (July 9, 2018); CPower/EnerNOC Supplemental Reply Comments at 2

63 See NSTAR Electric Company. D.P.U. 12-116 (Exh. DPU 1-7(d)).

64 While the AESC Study calculates a range of benefits between $59,100/MW per year to $154,900/MW per year from a resource participating in ISO-NE's DR programs, NECEC suggests that the ratepayer benefits from a solar resource need to be discounted, offering ratepayer benefits between $59,000/MW per year and $109,000/MW per year (NECEC Reply Comments at 7, fn. 12).

(July 31, 2018); DOER Reply Comments at 6 (July 25, 2018); NECEC Reply Comments at 6-8 (July 25, 2018); PowerOptions Comments at 3 (July 9, 2018)).

Some commenters maintain that the Distribution Companies should not enroll any DG Facilities they manage under Option 1 of the Compromise Proposal as a SOG and instead should enroll the facilities as passive DR, on-peak resources, because ratepayers may be subject to steep PFP penalties if ISO-NE declares a scarcity event and solar resources either were not producing or were not exporting to the grid due to on-site consumption (Cape Light Compact Reply Comments at 6 (July 25, 2018); CPower/EnerNOC Comments at 7, fn.8 (July 9, 2018); NECEC Reply Comments at 5 (July 25, 2018); Tesla Reply Comments at 3 (July 25, 2018)).

PowerOptions maintains that the Distribution Companies should not register NM facilities as SOGs but rather should allow the facilities to serve as load reducers, on peak resources or seasonal peak resources, because (1) NM facilities registered as SOGs are not fully accounted for by ISO-NE, as the facilities are not represented in the capacity markets; (2) SOGs do not decrease the ICR; (3) the region purchases more capacity than necessary to support the system; and (4) NM resources that act as load reducers will decrease the total capacity the region must procure, which will decrease costs for customers (PowerOptions Comments at 3 (July 9, 2018)).

NECEC argues that BTM resources that do not participate as SOGs in the ISO-NE energy market are able to reduce the Distribution Companies' load, which will result in avoided energy purchases and will reduce ratepayer energy costs in a manner similar to the offset provided by a SOG (NECEC Comments at 32 (July 9, 2018)). NECEC, EnerNOC, and CPower contend that it is no longer prudent to require the Distribution Companies to enroll BTM solar facilities as SOGs because (1) ISO-NE market rules have changed[65] and (2) requiring the enrollment of BTM solar as an SOG will eliminate one of the core business cases for BTM energy storage because storage will not be able to participate in the ISO-NE DR program (CPower/EnerNOC Comments at 4-5 (July 9, 2018); NECEC Comments at 31 (July 9, 2018)).

Tesla maintains that approving the load reducer option is essential to completing the framework on how capacity allocations should be assigned and for maximizing the benefits of NM facilities as well as solar and storage facilities (Tesla Reply Comments at 3 (July 28, 2018)). If the Department does not approve the load reducer option, Tesla requests that the Department permit stakeholders to continue a dialogue on the issue or to brief the issue more fully (Tesla Reply Comments at 4 (July 25, 2018)).

The Companies argue that the Department's key priority should be to maximize the value of energy and capacity to offset the high costs of the NM and SMART programs (Companies Reply Comments at 3). The Distribution Companies contend that the greatest benefit customers could realize from NM and SMART facilities would be monetizing the value of capacity and receiving the direct value of the energy from the ISO-NE wholesale markets, while allowing the Distribution Companies to share in the net value of the FCM revenue to help stimulate the competitive market (Companies Reply Comments at 3 (July 25, 2018)). National Grid explains that the Distribution Companies are currently required to register all Class II and III NM facilities as SOGs in the ISO-NE market because that is the only way to return value to

[65] On October 17, 2017, FERC approved a tariff change filing from ISO-NE that prevents a DR asset and a Generator Asset from being registered at the same end-use customer facility unless the Generator Asset is separately metered and reported and its output does not reduce the load reported at the Retail Delivery Point of the Demand Response Asset. (NECEC Reply Comments at 31, n. 23 citing FERC Docket No. ER17-2164-0000).

customers from energy products to offset the costs of NM and SMART programs (National Grid Comments at 21 (July 9, 2018)).

The Companies contend that the Department should not approve the load reducer option and, instead, the Department should let the Distribution Companies decide whether to allow facilities to act as load reducers or to register such facilities as SOGs in the ISO-NE market as they do now[66] (Companies Joint Reply Comments at 9-10 (July 25, 2018)). If the Department does approve the load reducer option, the Companies recommend that if facilities elect the load reducer option and decide to participate in wholesale capacity markets, the Facility Owners should be required to buyout the capacity according to the process in the Compromise Proposal (Companies Joint Reply Comments at 10 (July 25, 2018)).

C. Analysis and Findings

As an initial matter, the Department finds that we do not currently have enough information to make a final determination on whether a load reducer option should be included in the NM/SMART FCM Process. Consequentially, the Department will allow for a limited scope comment period to collect additional information, as detailed below in Section VIII. To inform this comment period, we will continue with our analysis of the load reducer option recommended in the Compromise Proposal and set forth a proposed, modified load reducer option for comment. In the interim period between the date of this Order and the Department's

[66] National Grid currently registers BTM NM facilities as SOGs (Companies Reply Comments at 9 (July 25, 2018)). The Department authorized Eversource to choose to have BTM Class II and Class III NM facilities act as load reducers as it found that the administrative cost of modeling such facilities did not justify the potential benefits of registering the facilities as SOGs (Companies Reply Comments at 9 (July 25, 2018)). NSTAR Electric Company, D.P.U. 12-116-B at 5-7 (2014).

decision following a limited-scope comment period, to preserve the possibility of a load reducer option, the Department directs the Distribution Companies to not participate in the FCM with any BTM Class II or III NM Facility. Facility Owners of eligible facilities may exercise the buyout option during this interim period.

The Department considers the following commenter recommendations for incorporation in the NM/SMART FCM Process: (1) allow any new or existing BTM Class II or III NM facility (regardless of whether it is paired with ESS) to act as a load reducer; (2) eliminate the obligation that Distribution Companies must register BM solar DG Facilities as SOGs with ISO-NE; (3) allow the Distribution Companies to determine whether facilities should act as load reducers or be registered as SOGs in the ISO-NE markets; and (4) require any HC that elects the load reducer option to buy out the capacity rights of its facility if the HC decides to participate in the ISO-NE FCM (Compromise Proposal at 6; Companies Joint Reply Comments at 10 (July 25, 2018)).

First, we consider whether to allow HCs of BTM NM facilities to elect to have their facility act as a load reducer and not participate in any ISO-NE market. The revenue offset to the NMRS provided from registering NM facilities as SOGs in the energy market is significant and helps to defray the cost of the NM program. In 2016, the offset to the NMRS from wholesale energy sold into the ISO-NE market amounted to $18,201,283.[67] The Department seeks to

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[67] See Fitchburg Gas and Electric Light Company, D.P.U. 16-188, Sch. DJD-1, at 2; Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 17-11, Exh. JEM-15, at 2; Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 18-01, Exh. JEM-15, Supplemental at 2; NSTAR Electric Company and Western Massachusetts Electric Company, D.P.U. 17-158, Exh. NSTAR RDC-1, at 1 and Exh. WMECO RDC-1, at 3.

maximize benefits to ratepayers by balancing the direct benefits from BTM NM facilities participating in the ISO-NE energy market as SOGs with the indirect benefits of BTM NM facilities acting as load reducers and reducing wholesale capacity and transmission costs by reducing peak demand. Reducing peak demand, especially by enabling clean resources, may reduce energy costs and emissions, both of which are key policy objectives of the Commonwealth (DOER Reply Comments at 6 (July 25, 2018)). See An Act Relative to Green Communities, St. 2008, c. 169; An Act to Promote Energy Diversity, St. 2016, c. 188; An Act to Advance Clean Energy, St. 2018, c. 227.

The Department is persuaded that allowing BTM NM facilities to act as load reducers will not have a significant impact on the cost offset to the NMRS as over 90 percent of the NMRS cost offset originates from FTM NM facilities which are not eligible for the load reducer option.[68] The Department currently allows the Distribution Companies to pursue different policies to monetize the value of certain NM facilities in the ISO-NE energy markets. Consistent with Model Net Metering Tariff, D.P.U. 09-03-A, the Department requires National Grid and Unitil to register Class II and III BTM NM facilities as SOGs. D.P.U. 09-03-A at 18, Appendix A at 10 (2009). Subsequently, the Department granted Eversource the discretion to allow BTM NM facilities to act as load reducers. NSTAR Electric Company, D.P.U. 12-116-B

[68] In 2012, Eversource testified that FTM NM generators accounted for 94 percent of the excess generation produced by NM customers. NSTAR Electric Company. D.P.U. 12-116, NSTAR Brief at 7, citing Exh. D.P.U. 1-7(d)). CPower and EnerNOC conducted an analysis of SREC I and SREC II facilities from publically available data, estimating that 90 percent to 95 percent of the energy revenue applied as the NMRS offset is attributed to standalone FTM solar facilities (Cpower and Enernoc Comments at 3, n.2 (July 9, 2018)).

at 5-7 (2014). The Department prefers to have consistent NM policy across Distribution Company service territories in the Commonwealth to avoid uncertainty for HCs.

On balance, the Department finds that establishing a load reducer option for BTM Class II and III NM facilities likely would have a negligible impact on the NMRS cost offset and would likely create the potential for greater benefits (i.e., reducing peak demand) for ratepayers, while also providing a consistent policy across the Commonwealth. As such, the Department will consider a load reducer option as part of the NM/SMART FCM Process with certain criteria. New BTM Class II and III NM facilities could elect the load reducer option up until they receive an ATI by notifying their Distribution Company in writing. A Distribution Company would not register any BTM Class II or III NM facilities with ISO-NE prior to a facility receiving an ATI. If a BTM Class II or III NM facility elects the load reducer option, the Distribution Company would not register that facility with the ISO-NE as a SOG or participate in any ISO-NE market. Existing BTM Class II and III NM facilities that chose to elect the load reducer option would be required to do so within a set timeframe by notifying their Distribution Company in writing. If an existing BTM Class II or Class III NM facility elects the load reducer option, the Distribution Company would delist the existing facility as a SOG with ISO-NE within 30 days of the HC's written notification and would not participate with the facility in any ISO-NE market.

Next, we consider whether a BTM Class II or III NM facility that elects the load reducer option should receive title to the facilities energy and capacity rights. The Compromise Proposal infers that HCs that elect the load reducer option would retain control of title to both the energy and capacity associated with their facility (Compromise Proposal at 6). Stakeholders in favor of the load reducer option maintain that by participating as load reducers, facility owners will not participate in any ISO-NE market (Attorney General Comments at 8-10 (July 9, 2018; CPower and EnerNOC Reply Comments at 2-3 (July 25, 2018); NECEC Reply Comments at 4 (July 25, 2018)). However, the load reducer section of the Compromise Proposal implies that a HC that elects to be a load reducer would be allowed to participate in the ISO-NE DR program (Compromise Proposal at 6). The Distribution Companies argue that if the Department approves the load reducer option and a facility elects the load reducer option but seeks to participate in wholesale capacity markets, the HC should be required to purchase the capacity according to the buyout process set forth in the Compromise Proposal (Companies Joint Reply Comments at 10 (July 25, 2018)).

By participating as a load reducer under ISO-NE's Operating Procedure No. 14, a HC cannot participate in any ISO-NE market.[69] The Department finds that allowing a facility electing the load reducer option to participate in the ISO-NE DR program would be contrary to ISO-NE's Operating Procedures and would deprive ratepayers of the potential revenue associated with participation in the DR program.[70] Under General Laws chapter 164 and the Department's related regulations at Title 220 of the Code of Massachusetts Regulations, the Department has substantial regulatory control over the Distribution Companies. However, the Department does not directly regulate the actions or inactions of a HC beyond the terms of a NM tariff. Therefore, if a HC of a facility electing the load reducer option is provided title to the

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69 ISO New England Operating Procedure No. 14 – Technical Requirements for Generators, Demand Response Resources, Asset Related Demands and Alternative Technology Regulation Resources, December 11, 2017, §II.A.2.

70 Stakeholders point to an AESC Study that estimates potential annual DR benefits in the range of $59,000/MW to $109,000/MW for load reducer facilities (NECEC Reply Comments at 7 (July 25, 2018)).

energy and capacity rights associated with that facility, the HC could subsequently decide to participate in the FCM and earn revenue without making a buyout payment to compensate ratepayers. As such, we find that if a load reducer option is included in the NM/SMART FCM Process, it would be in the best interest of ratepayers for the Distribution Companies to retain control of title to both the energy and capacity rights associated with a BTM Class II or III NM facility that elects the load reducer option. If a HC that initially elects to operate as a load reducer subsequently decides to monetize the value of its facility's capacity, the HC would be required to make a buyout payment to the Distribution Company that will to flow through the Distribution Company's NMRS and result in ratepayer benefits.

D. Solicitation of Comments

The Department seeks limited scope written comments on whether the load reducer option that the Department proposed above for inclusion in the NM/SMART FCM Process would provide enough indirect benefits to ratepayers to outweigh the direct benefits ratepayers could recognize from the Distribution Companies' participating in the ISO-NE energy market and FCM with all BTM Class II and III NM facilities. Initial written comments on this issue must be submitted no later than 5:00 p.m. on Friday, February 15, 2019. Any reply written comments are due no later than 5:00 p.m. on Friday, February 22, 2019. All comments should be limited in scope to the load reducer option. Comments outside of this limited scope would be out of order and subject to exclusion at the discretion of the Department.

IX. ISO-NE ENERGY MARKET

A. Introduction

ISO-NE operates three wholesale electricity markets in New England - the energy, capacity and ancillary services markets. The energy markets provide both day-ahead and real-time wholesale electric energy products to market participants. The Department requires the-Distribution Companies to register Class II and III NM facilities in the ISO-NE energy market as SOGs and to apply any energy market payments received from ISO-NE to offset the total costs of net metering recovered from all ratepayers through the NMRS. D.P.U. 09-03-A at 18. The Department currently allows Eversource the option to have BTM Class II and III NM facilities serve as load reducers. D. P. U. 12-116-B at 5-7.

In D.P.U. 17-140-A, the Department sought to avoid a situation where a facility's registration in the energy market during the Interim Period would restrict its future participation in the FCM. D.P.U. 17-140-A at 127. The Department balanced this concern with our interest in maximizing indirect benefits to ratepayers during the Interim Period and benefits to ratepayers following the Department's decision in this docket. D.P.U. 17-140-A at 127. Consequently, during the Interim Period, the Department prohibits Distribution Companies from registering BTM SMART facilities that are less than 60 kW and AOBCs in the energy market as SOGs. D.P.U. 17-140-A at 127.

B. Summary of Comments

Stakeholders acknowledge the need to maximize the benefits of the NM and SMART programs for ratepayers by enrolling facilities in the ISO-NE energy market to offset program costs (Attorney General Comments at 3 (July 9, 2018); CPower and EnerNOC Comments at 3 (July 9, 2018) DOER Comments at 3-4 (July 9, 2018) NECEC Comments at 2 (July 9, 2018)).

Some commenters argue that the Department should not continue to require the Distribution Companies to register BTM DG Facilities as SOGs because (1) the NMRS offset to ratepayers from ISO-NE energy market revenues will remain largely intact as approximately 90 to 95 percent of the NMRS offset is from FTM solar facilities,[71] rather than BTM solar facilities; (2) the SOG requirement deprives ratepayers of capacity market benefits as it prevents the ISO-NE from counting the contribution of a NM facility towards reducing the ICR requirement and capacity prices for ratepayers; (3) a change in ISO-NE rules prevents a BTM facility registered as an SOG in the energy market from participating in the ISO-NE DR program; (4) participation in the ISO-NE DR market is an important opportunity for energy storage facilities without which the nascent storage market in Massachusetts would be jeopardized; and (5) precluding participation in the ISO-NE DR program will conflict with the Green Communities Act requiring electric and natural gas resource needs be met first through all available energy efficiency and demand reduction resources that are cost effective or less expensive than supply resources (CPower and EnerNOC Comments at 2-10 (July 9, 2018); DOER Reply Comments at 6 (July 25, 2018); NECEC Comments at 8 (July 9, 2018)).

National Grid explains that the Distribution Companies are currently required to register all Class II and III NM facilities as SOGs in the ISO-NE energy market because that is the only

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71 Some stakeholders recommend that their proposed tariff change apply only to BTM solar NM facilities and not to FTM solar NM facilities (Attorney General Comments at 9 (July 9, 2018); CPower and EnerNOC Comments at 3, n.2, 4 (July 9, 2018); DOER Reply Comments at 6 (July 25, 2018); NECEC Comments at 8 (July 9, 2018)).

way to credit value to customers from energy products to offset the costs of the NM and SMART programs (National Grid Comments at 21 (July 9, 2018)). The Companies argue that the Department's key priority should be to maximize the value of energy and capacity to offset the high costs of the NM and SMART programs for the benefit of distribution customers (Companies Joint Reply Comments at 3).

The Companies argue that the Distribution Companies should still be required to register NM facilities as SOGs in the ISO-NE energy market, unless Facility Owners propose another option that provides customer value, such as paying the Distribution Company for the forgone energy market revenue to offset NM and SMART program costs (National Grid Comments at 21-22 (July 9, 2018); Eversource Comments at 11 (July 9, 2018)).

The Compromise Proposal recommends that the Department maintain the requirement in D.P.U. 09-03-A and in the Distribution Companies' NM tariffs that the Distribution Companies register all FTM Class II and III NM facilities as SOGs with ISO-NE and credit any proceeds obtained through participation in the ISO-NE energy market to ratepayers through the NMRS (Compromise Proposal at 5). The Compromise Proposal also recommends that the Distribution Companies include a similar requirement in the SMART Provision for FTM SMART facilities (Compromise Proposal at 5). The Compromise Proposal further recommends that the Department direct the Distribution Companies to modify the NM tariffs to remove the requirement that Distribution Companies register all BTM Class II and III NM facilities as SOGs with ISO-NE (Compromise Proposal at 5-6).

C. Analysis and Findings

The Department agrees with the majority of stakeholders that it is important to maximize the benefits of the NM and SMART programs for ratepayers by enrolling DG Facilities in the ISO-NE energy market and using revenues obtained to offset program costs (Attorney General Comments at 3 (July 9, 2018); CPower and EnerNOC Comments at 3 (July 9, 2018); DOER Comments at 3-4 (July 9, 2018); NECEC Comments at 2 (July 9, 2018)). The Department acknowledges, however, that there is a relationship between facility registration with ISO-NE for participation in the energy market and a facility's participation in the FCM. ISO Tariff, § III.8.1.1(d), § III.13; D.P.U. 17-146, ISO-NE Presentation Slides (June 4, 2018). For example, if a facility is registered in the energy market as a SOG, that facility is limited by ISO-NE rules as to how it may seek to participate in the FCM. ISO Tariff, § III.8.1.1(d). And if a facility is registered as a SOG, the associated capacity for that facility is registered with ISO-NE and is not treated as a load reducer. ISO Tariff, § III.8.1.1(d). These complexities did not exist to the same extent when the Department first required Distribution Companies to register all Class II and III NM facilities as SOGs with ISO-NE.

To properly execute several of the Department's directives in this Order, the Distribution Companies cannot be obligated to register all Class II and III NM facilities as SOGs with ISO-NE. As stated above, in establishing the various aspects of the NM/SMART FCM Process, the Department finds that some situations may exist whereby the Department's objectives as well as ratepayer and stakeholder interests can be best served by allowing certain Class II and III NM facilities to act as load reducers and not participate in the ISO-NE energy market or by allowing Facility Owners to buyout the capacity rights for their DG Facility. Further, the Department notes that it currently requires National Grid and Unitil to register BTM Class II and III NM facilities as SOGs while Eversource may choose to have BTM NM facilities act as load reducers. The Department seeks to implement a NM/SMART FCM Process that is consistent across Distribution Company service territories.

As discussed above, we are persuaded that 90 to 95 percent of the NMRS offset is produced by FTM NM facilities (see Sections VI and VIII). Since FTM Class II and III NM facilities provide the majority of proceeds from the ISO-NE energy market to offset the costs of the NM program, we find that registration as SOGs in the ISO-NE energy market for FTM Class II and III NM facilities is essential to maintaining the NM program. Likewise, without further information, we find that registration of FTM SMART facilities as SOGs with ISO-NE is essential to adequately offset SMART program costs and to ensure the success of the program. We are persuaded, however, that some circumstances, such as the buyout option and possibly the load reducer option, justify allowing the Distribution Companies to not register certain DG Facilities as SOGs with ISO-NE. Accordingly, the Department directs each Distribution Company to revise its NM tariff to remove the requirement that the Distribution Company register as SOGs in the ISO-NE energy market (1) BTM Class II and III NM facilities and (2) FTM solar Class II and III NM facilities paired with ESS that exercise the buyout option. The Distribution Companies are required to register as SOGs in the ISO-NE energy market all FTM Class II and III NM facilities, other than FTM solar Class II and III NM facilities paired with ESS that exercise the buyout option, and to credit all revenue earned through participation in the energy market to ratepayers through the NMRS. Each Distribution Company is further directed to revise its SMART Provision to include a requirement that the Distribution Companies register as SOGs in the ISO-NE energy market all FTM SMART facilities that are not paired with ESS and exercise the buyout option, and to credit all revenue earned through participation in the ISO-NE energy market to ratepayers through the SMART Factor.

X. SMALL HYDROELECTRIC FACILITIES

A. Introduction

On August 8, 2016, Governor Baker signed into law Chapter 188 of the Acts of 2016, An Act to Promote Energy Diversity ("Energy Diversity Act"). Among other things, the Energy Diversity Act required the Department to amend its rules and regulations implementing a new NM provision concerning small hydroelectric power NM facilities, G.L. c. 164, § 139A. St. 2016, c. 188, § 10. The Department completed a rulemaking proceeding to establish the SHP that expands NM services for small hydroelectric NM facilities to implement G.L. c. 164, § 139A. Net Metering Rulemaking, D.P.U. 17-10-A (2017); 220 CMR 18.00.

The Department established that the SHP is an independent program that is separate and distinct from the general NM program ("GP"). D.P.U. 17-10-A at 7-8 . The NM regulations exclude SHP facilities from the Class I, Class II, and Class III definitions because the SHP does not differentiate between classes. 220 CMR 18.02; D.P.U. 17-10-A at 8-9. The SHP, as distinct from the GP, also does not distinguish between public and private facilities. D.P.U. 17-10-A at 8-9. The Department approved revised NM tariffs, incorporating the SHP that specified that the Distribution Companies do not have the ability to seek capacity payments from ISO-NE for SHP facilities. Hearing Officer Memorandum, Net Metering Tariff, D.P.U. 18-04 (June 18, 2018). We consider whether to continue such treatment for SHP facilities.

B. Summary of Comments

BSHA argues that the capacity rights of facilities in the SHP should be owned exclusively by the facility owner and that the Distribution Companies should not have rights to such capacity (BSHA Reply Comments at 2 (February 22, 2018)). BSHA notes that the Department's 2009 decision to grant the Distribution Companies a right of first refusal to the capacity rights of Class II and III NM facilities took place well before the SHP was established (BSHA Reply Comments at 2 (February 22, 2018)). BSHA argues that the Department specifically exempted SHP facilities from the Class II and III regulatory definitions and that the Distribution Companies should not have ownership interest in such facilities (BSHA Reply Comments at 3 (February 22, 2018)). Additionally, BSHA explains that capacity rights of SHP facilities are not separated from the facility's owner in the model NM tariff or final Order in D.P.U 17-10-A (BSHA Reply Comments at 3 (February 22, 2018)). BSHA maintains that the SHP has its own distinctive characteristics, a separate statutory provision, and unique public policy purpose as compared to the GP (BSHA Reply Comments at 3-4 (February 22, 2018); BSHA Compromise Proposal Comments at 3 (July 9, 2018); BSHA Compromise Proposal Reply Comments at 2-3 (July 25, 2018)).

BSHA explains that if a Distribution Company is granted the option to assert title to the capacity rights of a SHP facility, the Distribution Company must assert title to the capacity rights within a 30-day window or title should transfer to the facility owner (BSHA Reply Comments at 4 (February 22, 2018)). BSHA proposes that a Distribution Company that asserts capacity rights to a SHP facility should qualify and bid the asset in the FCM during the next FCA or face consequences for not doing so (BSHA Reply Comments at 5-6 (February 22, 2018)).

Some commenters argue that because SHP facilities receive NM credits just as any other facility participating in the GP they should be treated in line with the Compromise Proposal (DOER Comments at 10 (July 9, 2018); National Grid Comments at 21 (July 9, 2018); Companies Reply Comments at 2, n.5 (July 28, 2018)). BSHA disagrees and argues that the statute creating the SHP purposely limited the credit value for small hydro NM facilities with the understanding that other revenue opportunities would be available (BSHA Reply Comments at 3 (July 25, 2018), citing G.L. c. 164, § 139A). BSHA supports the Compromise Proposal to the extent that it does not extend its terms to SHP facilities (BHSA Compromise Proposal Reply Comments at 1 (July 31, 2018)).

C. Analysis and Findings

The Legislature has not addressed the capacity rights associated with any particular NM facilities, with the exception of requiring Class II and III net metering facilities to provide all necessary information to, and cooperate with, a Distribution Company to enable the Distribution Company to obtain the appropriate asset identification for reporting generation to ISO-NE. G.L. c. 164, § 139(d). Notably, this section of the General Laws does not apply to SHP facilities. The Legislature clearly created a separate and distinct SHP with a NM credit value that is lower than all other NM technologies. G.L. c. 164, §§ 138, 139, 139A.

Where there is a statutory gap, the agency charged with the administration of a statute is to spell out details of the legislative policy. United States v. Mead Corporation, 533 U.S. 218, 227 (2001), citing Chevron U.S.A., Inc. v. Natural Resources Defense Council, 467 U.S. 837, 843-844 (1984); Middleborough v. Housing Appeals Committee, 449 Mass. 514, 523 (2007), citing Zoning Board of Appeal of Wellesley v. Housing Appeals Committee, 385 Mass. 651, 654

(1982). In accordance with Massachusetts law, the Department seeks to interpret statutes as a whole, where possible. District Attorney for the Northwestern District v. Eastern Hampshire Division of the District Court Department, 452 Mass. 199, 210 (2008) (finding wherever possible, statutes should be interpreted as a whole to constitute a consistent and harmonious provision).

The Department already established that facilities in the SHP are not Class I, Class II, or Class III NM facilities. 220 CMR 18.02; D.P.U. 17-10-A at 8-9. The Compromise Proposal excludes SHP facilities because it applies to Class II and III NM facilities and to SMART facilities that are receiving AOBCs (Compromise Proposal at 2). The Department finds it appropriate to continue to recognize that SHP facilities are distinct from other types of NM facilities. This finding recognizes the Legislature's intent to provide incentives to existing small hydroelectric NM facilities to support facility owner's ability to fund ongoing maintenance and operations. G.L. c. 164, § 139A. The Department finds that HCs of SHP facilities shall hold title to the capacity rights associated with their facilities, while the Distribution Companies shall continue to retain title to the energy rights associated with SHP facilities and use and revenue obtained from participation in the energy market with SHP facilities to offset the NMRS. The Department directs the Distribution Companies to provide all documents necessary to transfer title to the capacity rights of a SHP facility to the associated HC within 30 business days of the date of this Order for an existing facility and within 15 business days of confirmation that the facility will take service under the NM tariff for a new facility. The Distribution Companies are not required to register SHP facilities in the energy market as SOGs.

XI. TARIFF REVISIONS

A. Net Metering Tariff

Each Distribution Company must revise its NM tariff as follows. Section 1.03 may be revised to reflect that any metering or information that a Distribution Company may need to comply with the NM/SMART FCM Process requirements approved herein. Section 1.08 must be revised to reflect the requirements of the NM/SMART FCM Process, including clearly indicating that the capacity rights associated with Class II and III NM facilities automatically transfer to the Distribution Company upon enrollment in the NM tariff and that the Distribution Company is obligated to participate in the FCM with DG Facilities under either Option 1 or Option 2. This section also must be revised to include the buyout process and formula and to specify that the Distribution Company will not retain capacity rights associated with SHP facilities nor the energy or capacity rights associated with Class I NM facilities or ESS paired with a NM facility. Section 1.08 must be further revised to amend the language requiring all Class II and III NM facilities to be registered as SOGs with ISO-NE, to retain the requirement only for FTM Class II and III NM facilities that are not paired with ESS and exercise the buyout option. Other Sections of the NM tariffs should be revised as necessary to implement the NM/SMART FCM Process.

B. SMART Provision

Each Distribution Company must revise its SMART Provision as follows. Section 6.3.4 must be revised to reflect the requirements of the NM/SMART FCM Process, including clearly indicating that capacity rights of SMART AOBC facilities automatically transfer to the Distribution Company upon enrollment in the SMART Provision and that the Distribution

Company is obligated to participate in the FCM with DG Facilities under either Option 1 or Option 2. Section 6.3.4 also must be revised to include the buyout process and formula and to specify that the Distribution Company will not retain the energy or capacity rights associated with an ESS paired with a SMART facility. Section 13.0 must be revised to incorporate the market revenue associated with capacity payments. Alternatively, a Distribution Company may alter the market revenue definition in Section 2.18.[72] Section 17.0 must be revised to include additional terms discussed herein regarding the buyout option and information sharing to permit a Distribution Company to participate in the FCM. Other Sections of the SMART Provisions must be revised, as necessary, to implement the NM/SMART FCM Process, including the requirement to register all FTM Class II and III NM facilities that are not paired with ESS and exercise the buyout option as SOGs in the ISO-NE energy market.

C. Next Steps

The Distribution Companies shall jointly file a revised model NM tariff and a revised model SMART Provision in a new docket. Interested stakeholders will have the opportunity to participate in the new docket.

XII. ORDER

Accordingly, after notice, opportunity to comment, and due consideration it is

ORDERED: That Fitchburg Gas and Electric Light Company d/b/a Unitil, Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid, and NSTAR Electric Company d/b/a Eversource Energy shall file for Department approval a revised model

[72] The Department directs the Distribution Companies to confer on this revision regarding market revenue and to propose a uniform approach.

net metering tariff and a revised model SMART Provision within ten calendar days of this Order; and it is

FURTHER ORDERED: That Fitchburg Gas and Electric Light Company d/b/a Unitil, Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid, and NSTAR Electric Company d/b/a Eversource Energy shall comply with all directives contained in this Order; and it is

FURTHER ORDERED: That the Secretary of the Department shall send a copy of this Order to each electric distribution company subject to the jurisdiction of the Department under G.L. c. 164, and shall ensure service on stakeholders on the distribution list in D.P.U. 17-146 and service list in D.P.U. 17-140, which service may be made by electronic means.

By Order of the Department,

/s/
Angela M. O'Connor, Chairman

/s/
Robert E. Hayden, Commissioner

/s/
Cecile M. Fraser, Commissioner