The Commonwealth of Massachusetts

DEPARTMENT OF PUBLIC UTILITIES

D.P.U. 18-64 June 25, 2019

Petition of NSTAR Electric Company d/b/a Eversource Energy for approval by the Department of Public Utilities of a long-term contract for procurement of clean energy generation, pursuant to Section 83D of An Act Relative to Green Communities, St. 2008, c. 169, as amended by St. 2016, c. 188, § 12.

D.P.U. 18-65

Petition of Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid for approval by the Department of Public Utilities of a long-term contract for procurement of clean energy generation, pursuant to Section 83D of An Act Relative to Green Communities, St. 2008, c. 169, as amended by St. 2016, c. 188, § 12.

D.P.U. 18-66

Petition of Fitchburg Gas and Electric Light Company d/b/a Unitil for approval by the Department of Public Utilities of a long-term contract for procurement of clean energy generation, pursuant to Section 83D of An Act Relative to Green Communities, St. 2008, c. 169, as amended by St. 2016, c. 188, § 12.

APPEARANCES: Danielle Winter, Esq.
Kerri A. Mahoney, Esq.
Keegan Werlin LLP
99 High Street, Suite 29th Floor
Boston, Massachusetts 02110
FOR: NSTAR ELECTRIC COMPANY
Petitioner (D.P.U. 18-64)

Laura Bickel, Senior Counsel
National Grid
40 Sylvan Road
Waltham, Massachusetts 02451
-and-
John K. Habib, Esq.
Matthew S. Stern, Esq.
Ashely S. Wagner, Esq.
Keegan Werlin LLP
99 High Street, 29th Floor
Boston, Massachusetts 02110
FOR: MASSACHUSETTS ELECTRIC COMPANY AND NANTUCKET ELECTRIC COMPANY
Petitioners (D.P.U. 18-65)

Gary Epler, Chief Regulatory Counsel
Unitil Service Corp.
6 Liberty Lane West
Hampton, New Hampshire 03842
-and-
William D. Hewitt, Esq.
Roach Hewitt Ruprecht Sanchez & Bischoff, PC
66 Pearl Street
Portland, Maine 04101
FOR: FITCHBURG GAS AND ELECTRIC LIGHT COMPANY
Petitioner (D.P.U. 18-66)

Maura Healey, Attorney General
Commonwealth of Massachusetts
By: Elizabeth L. Mahony
Shannon Beale
Matthew Saunders
Cristina Belew
Assistant Attorneys General
Office of Ratepayer Advocacy
One Ashburton Place
Boston, Massachusetts 02108
Intervenor

Robert Hoaglund, Esq.
Ben Dobbs, Esq.
Colin P. Carroll, Esq.
Tanya Larrabee, Esq.
100 Cambridge Street, Suite 1020
Boston, Massachusetts 02114
FOR: MASSACHUSETTS DEPARTMENT OF ENERGY RESOURCES
Intervenor

Amy E. Boyd, Esq.
Acadia Center
31 Milk Street, Suite 501
Boston, Massachusetts 02109
FOR: ACADIA CENTER

Andrew O. Kaplan, Esq.
Pierce Atwood LLP
100 Summer Street
Boston, Massachusetts 02110
-and-
Jared S. des Rosiers, Esq.
Pierce Atwood LLP
254 Commercial Street
Portland, Maine 04101
-and-

R. Scott Mahoney, Esq.
Carlisle McLean, Esq.
AVANGRID, Inc.
One City Center, 5th Floor
Portland, Maine 04101
-and-
Paul G. Afonso, Esq.
Jed M. Nosal, Esq.
Brown Rudnick LLP
One Financial Center
Boston, Massachusetts 02110
FOR: CENTRAL MAINE POWER COMPANY
Intervenor

Zori G. Ferkin, Esq.
Terrence B. Burek, Esq.
Kelsey Desloover, Esq.
King & Spalding LLP
1700 Pennsylvania Avenue, NW, Suite 200
Washington, DC 20006
FOR: CHAMPLAIN VT LLC
Intervenor

Caitlin Peale Sloan, Esq.
David Ismay, Esq.
Conservation Law Foundation
62 Summer Street
Boston, Massachusetts 02110
FOR: CONSERVATION LAW FOUNDATION
Intervenor

Jerrold Oppenheim, Esq.
57 Middle Street
Gloucester, Massachusetts 01930
-and-
Charles Harak, Esq.
National Consumer Law Center
7 Winthrop Square
Boston, Massachusetts 02110
FOR: LOW-INCOME WEATHERIZATION AND
FUEL ASSISTANCE PROGRAM NETWORK
Intervenor

David W. Bogan, Esq.
Locke Lord LLP
111 Huntington Avenue, 9th Floor
Boston, Massachusetts 02199
-and-
Brian J. Murphy, Esq.
NextEra Energy Resources, LLC
700 Universe Boulevard
Juno Beach, Florida 33408
FOR: NEXTERA ENERGY RESOURCES, LLC
Intervenor

Robert A. Rio, Esq.
Associated Industries of Massachusetts
One Beacon Street, 16th Floor
Boston, Massachusetts 02109
FOR: ASSOCIATED INDUSTRIES OF MASSACHUSETTS
Limited Participant

Nora Healy, Esq.
William Harwood, Esq.
Verrill Dana LLP
P.O. Box 586
Portland, Maine 04112
FOR: EMERA INC.
Limited Participant

Nadine Ganesan, Esq.
Hélene Cossette, Esq.
H.Q. Energy Services (U.S.) Inc.
75 René-Lévesque West
Montréal, Québec, Canada H2Z 1A4
FOR: H.Q. ENERGY SERVICES (U.S.) INC.
Limited Participant

Mark C. Kalpin, Esq.
Holland & Knight LLP
10 St. James Avenue, 11th Floor
Boston, Massachusetts 02116
FOR: NEW ENGLAND POWER GENERATORS ASSOCIATION, INC.
Limited Participant

Barry Needleman, Esq.
McLane, Middleton, PC
900 Elm Street, Box 326
Manchester, New Hampshire 03105
-and-
Elizabeth F. Mason, Esq.
McLane, Middleton, PC
300 TradeCenter Drive, Suite 7000
Woburn, Massachusetts 01801
FOR: NORTHERN PASS TRANSMISSION LLC
Limited Participant

Francis E. Pullaro, Esq.
RENEW Northeast, Inc.
P.O. Box 383
Madison, Connecticut 06443
FOR: RENEW NORTHEAST, INC.
Limited Participant

Stephen M. Linsky, Esq.
P.O. Box 525
Easthampton, Massachusetts 01027
-and-
Joshua A. Berman, Esq.
Sierra Club
50 F Street, 8th Floor
Washington, DC 20001
FOR: SIERRA CLUB
Limited Participant

Kelly Caiazzo, Esq.
Kevin Conroy, Esq.
Foley Hoag LLP
155 Seaport Boulevard
Boston, Massachusetts 02210
FOR: VINEYARD WIND LLC
Limited Participant

Jay Myers, Esq.
Locke Lord Public Policy Group LLC
111 Huntington Avenue
Boston, Massachusetts 02199
FOR: THE ENERGY CONSORTIUM
Limited Participant (D.P.U. 18-64)

Robert R. Ruddock, Esq.
Locke Lord Public Policy Group LLC
111 Huntington Avenue
Boston, Massachusetts 02199
FOR: WESTERN MASSACHUSETTS INDUSTRIAL GROUP
Limited Participant (D.P.U. 18-64)

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I. INTRODUCTION

On July 23, 2018, NSTAR Electric Company d/b/a Eversource Energy ("Eversource"), Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid ("National Grid"), and Fitchburg Gas and Electric Light Company d/b/a Unitil ("Unitil") (collectively, "Companies") filed separate petitions with the Department of Public Utilities ("Department"), pursuant to Section 83D of An Act Relative to Green Communities, St. 2008, c. 169 ("Section 83D")[1] and 220 CMR 24.00, et seq., for approval of individual long-term contracts to purchase hydroelectric generation and associated environmental attributes. The Department docketed the Eversource petition as D.P.U. 18-64, the National Grid petition as D.P.U. 18-65, and the Unitil petition as D.P.U. 18-66.

Section 83D requires each electric distribution company to jointly and competitively solicit proposals for eligible clean energy generation resources[2] no later than April 1, 2017, and, provided reasonable proposals have been received, to enter into cost-effective long-term contracts to facilitate the financing of clean energy generation resources equal to

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1 Section 83D was added to An Act Relative to Green Communities by An Act To Promote Energy Diversity, St. 2016, c. 188, § 12.

2 For the purpose of Section 83D, the term "clean energy generation" is defined as (1) firm service hydroelectric generation from hydroelectric generation alone, (2) new Class I Renewable Portfolio Standard ("RPS") eligible resources that are firmed up with firm service hydroelectric generation, or (3) new Class I RPS-eligible resources. St. 2008, c. 169, § 83B ("Section 83B"); 220 CMR 24.02.

approximately 9,450,000 megawatt-hours ("MWh") by December 31, 2022.[3] Section 83D(a),(b); 220 CMR 24.03. The Department must approve a long-term contract before it can become effective. Section 83D(e); 220 CMR 24.03.

On August 15, 2018, the Department held a joint public hearing and procedural conference in the three dockets.[4] The Attorney General of the Commonwealth of Massachusetts ("Attorney General") filed a Notice of Intervention in each proceeding pursuant to G.L. c. 12, § 11E(a). The Department granted petitions to intervene as full parties in each proceeding filed by the Department of Energy Resources ("DOER"), Acadia Center, Central Maine Power Company ("CMP"), Champlain VT LLC d/b/a TDI New England ("TDI-NE"), Conservation Law Foundation ("CLF"), Low-Income Weatherization and Fuel Assistance Program Network ("LEAN"), and NextEra Energy Resources, LLC ("NextEra"). The Department granted limited participant status in each proceeding to Associated Industries of Massachusetts ("AIM"), Emera Inc. ("Emera"), H.Q. Energy Services (U.S.) Inc. ("HQUS"), New England Power Generators Association, Inc. ("NEPGA"), Northern Pass Transmission LLC ("NPT"), RENEW Northeast, Inc. ("RENEW"), Sierra Club, and Vineyard Wind LLC ("Vineyard Wind"). The Department

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3 The Companies may conduct one or more competitive solicitations through a staggered procurement schedule. Section 83D(b); 220 CMR 24.04(5)

4 The Department held a joint public hearing in each docket. These cases, however, are not consolidated and remain separate proceedings.

granted limited participant status in D.P.U. 18-64 to The Energy Consortium ("TEC") and the Western Massachusetts Industrial Group ("WMIG").

Pursuant to Section 83D(f) and 220 CMR 24.04(6), DOER and the Attorney General jointly selected Peregrine Energy Group, Inc. as the Independent Evaluator to provide a report analyzing the solicitation and bid selection processes in a fair and unbiased manner. On July 24, 2018, the Independent Evaluator submitted its report ("IE Report")[5] describing the solicitation, evaluation, bid selection, and contract negotiation process.[6] On September 6, 2018, the Attorney General submitted her recommendations to the Department regarding the long-term contracts.[7]

On February 25, 26, and 28, 2019, the Department held joint evidentiary hearings. In each of the proceedings, the Companies sponsored the testimony of the following witnesses: (1) Nicholas H. Baldenko, Engineer for Eversource; (2) Timothy J. Brennan, Director in Regulatory Strategy and Integrated Analytics, National Grid USA Service

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5 On August 8, 2018, the Independent Evaluator submitted a revised report to correct an error in its description of certain calculations. All references to the "IE Report," herein, are to the revised report filed on August 8, 2018.

6 The Department moved the Independent Evaluator Report into the evidentiary record in each proceeding. <u>Long-Term Contracts for Clean Energy Generation under Section 83D</u>, D.P.U. 18-64, D.P.U. 18-65, D.P.U. 18-66, Hearing Officer Memorandum at 2 (September 6, 2018).

7 Pursuant to Section 83D(e) and 220 CMR 24.05(2), the Attorney General shall, within 45 days following the filing of the proposed contracts, submit her recommendations to the Department for its consideration. The Department incorporates its consideration of the Attorney General's recommendations throughout this Order.

Company, Inc.; (3) Robert S. Furino, Director, Energy Contracts for Unitil Service Corp.; (4) Robert B. Hevert, Partner, ScottMadden, Inc.; (5) Alexsandr Rudkevich, Principal, Tabors Caramanis Rudkevich; (6) George E. Tyson II, Executive Advisor, ScottMadden, Inc.; and (7) Jeffrey S. Waltman, Manager, Planning and Power Supply, Massachusetts regulated operating companies of Eversource. In each of the proceedings, the Attorney General sponsored the testimony of (1) Dean M. Murphy, Principal, The Brattle Group, and (2) Vincent Musco, Managing Director, Bates White Economic Consulting. Finally, in each of the proceedings, DOER sponsored the testimony of (1) Joanne Morin, DOER Deputy Commissioner, and (2) Joanna Troy, DOER Manager of Policy Initiatives.

On March 22, 2019, the Companies (jointly), the Attorney General, DOER, CLF, CMP, HQUS, NEPGA, NextEra, RENEW, Sierra Club, and WMIG submitted initial briefs. On April 3, 2019, the Companies (jointly),[8] the Attorney General, DOER, Acadia Center, CLF, CMP, HQUS, NEPGA, NextEra, Sierra Club, TEC, and WMIG submitted reply briefs. The record in each docket includes 376 exhibits, including responses to 329 information requests and five record requests.

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8 On this same date, National Grid submitted an individual supplement, while Unitil and Eversource submitted a joint supplement to the Companies' Reply Brief.

II. DESCRIPTION OF THE PROJECT

As further described in Section V, below, the Companies jointly solicited bids for clean energy generation resources.[9] As a result of this solicitation, each company seeks Department approval of a power purchase agreement ("PPA") to acquire its apportioned share of an annual aggregate quantity of 9,554,940 MWh of hydroelectric generation and associated environmental attributes[10] from HQUS, an affiliate of Hydro-Québec,[11] to be delivered into New England over new transmission infrastructure, referred to as the New England Clean Energy Connect ("NECEC") transmission line,[12] in accordance with a transmission service agreement ("TSA") between each company and CMP.[13]

CMP will make transmission capacity on NECEC[14] available to the Companies to deliver electrical energy, as scheduled by the Companies, up to 1,090 MW measured at the

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9 On March 27, 2017, the Department approved the timetable and method of solicitation in Long-Term Contracts for Clean Energy Generation Request for Proposals, D.P.U. 17-32 (2017).

10 "Environmental attributes" are New England Power Pool ("NEPOOL") Generation Information System ("GIS") certificates and any other present or future environmental benefits associated with the firm service hydroelectric generation (Exh. JU-2, at 5).

11 HQUS is a wholly-owned subsidiary of Hydro-Québec. Hydro-Québec operates electric power generation, transmission, and distribution systems in the Canadian province of Québec (Exh. IE Report at 2).

12 To deliver the hydroelectric generation into New England from Canada, CMP intends to develop, construct, own, and maintain a 1,200 megawatt ("MW") +/- 320 kilovolt ("kV") high-voltage direct current ("HVDC") transmission line extending from the United States border at Beattie Township, Maine to a new direct current ("DC") to alternating current ("AC") converter station in Lewiston, Maine (the "HVDC line") (Exh. JU-1, at 37). To interconnect the HVDC line with the bulk power system in New England, CMP intends to develop, construct, own and maintain a network of

delivery point in Lewiston, Maine (Exh. JU-1, at 37). The target date for commercial operation of NECEC is December 13, 2022 (Exh. JU-1, at 39). The commercial operation date may be extended by up to four six-month periods, for a maximum combined period of two years, but not to extend beyond December 13, 2024, unless the extension is due to a regulatory approval delay or an event of force majeure (Exh. JU-1, at 39-40).

III. DESCRIPTION OF PROPOSED CONTRACTS

A. Introduction

The Companies jointly conducted negotiations with HQUS resulting in three individual PPAs (Exh. JU-1, at 8). Principal contract terms, including price and contract duration, do not vary among the PPAs (Exhs. JU-1, at 8-9; JU-3-A at Exhibit D; JU-3-B at Exhibit D; JU-3-C at Exhibit D; ; JU-4-A at Att. J; JU-4-B at Att. J; JU-4-C at Att. J.[15] However, the

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additional 345 kilowatt ("kW") AC transmission lines, rebuilt 115 kW AC transmission lines, and other substation equipment (collectively, this network of transmission infrastructure is referred to as the "AC line") (Exh. JU-1, at 37). Together, the HVDC line and the AC line comprise NECEC (Exh. JU-1, at 37).

13 On October 19, 2018, the Federal Energy Regulatory Commission ("FERC") accepted the TSAs for effect October 20, 2018. Central Maine Power Company, 165 FERC¶61,034 (2018).

14 In conjunction with NECEC, Hydro-Québec TransÉnergie, an affiliate of HQUS, will develop, construct, own, and maintain the segment of the transmission line from the converter station at the Appalaches substation in Thetford Mines, Québec to the United States border ("Québec Line") (Exhs. JU-1, at 38 n.11; JU-4-A; JU-4-B; JU-4-C).

15 Differences among the PPAs include the following: (1) under the National Grid PPA, in the event that HQUS defaults as the result of a non-excused outage of NECEC, the seller termination payment is based on exposure over a 60-month period, while under the Eversource and Unitil PPAs, that payment is based on exposure over the entire remaining PPA term (Exhs. JU-3-A at 50-51; JU-3-B at 58-59; JU-3-C at 44-45);

quantities of energy and environmental attributes vary based on each electric distribution company's apportioned share of the aggregate total (Exh. JU-1, at 16-17, 27).[16]

B. Products and Pricing Structure

The PPAs provide for the delivery of an aggregate of 9,554,940 MWh annually of hydroelectric generation and related environmental attributes from HQUS delivered through NECEC (Exh. JU-1, at 36). The PPAs have a term of 20 years from the date of commercial operation of NECEC (Exh. JU-1, at 36). The PPAs impose a firm obligation on HQUS to provide qualified clean energy and associated environmental attributes in accordance with a specified delivery schedule (Exh. JU-1, at 36). HQUS will transfer energy to the Companies through internal bilateral transactions executed through ISO-New England Inc. ("ISO-NE") and settled at the southern terminus of NECEC in Lewiston, Maine ("delivery point") (Exh. JU-1, at 36). The PPAs obligate the Companies to purchase the lesser of the total

(2) the National Grid PPA contains National Grid-specific credit and credit support requirements (Exh. JU-3-B at 35-41); (3) the National Grid PPA includes a statement regarding allocation of the purchase price between energy and environmental attributes (Exh. JU-3-B at Exhibit D); (4) the forms of guaranty provided to National Grid and Unitil differ from the form of guarantee provided to Eversource (Exhs. JU-3-A at Exhibit G; JU-3-B at Exhibit G; JU-3-C at Exhibit G); and (5) the baseline hydroelectric generation delivery commitment volume for National Grid is based on an initial annual volume of 9.45 terawatt-hours ("TWh") subject to certain potential adjustments, while the Eversource and Unitil initial annual volumes are each three TWhs, adjusted only for force majeure events (Exhs. JU-3-A at Exhibit H; JU-3-B at Exhibit H; JU-3-C at Exhibit H).

16 Section 83D(g) provides that each company's apportioned share of the products being purchased shall be based upon the total energy demand from all distribution customers in its service territory.

metered output generated by HQUS' designated resources and the amount of qualified clean energy delivered to the delivery point in any given period (Exh. JU-1, at 36). HQUS will also transfer all environmental attributes associated with qualified clean energy or qualified shortfall energy[17] paid for by the Companies under the PPA (Exh. JU-1, at 36).

The PPAs provide for a schedule of fixed prices for energy, including environmental attributes, over each year of the PPA, at the same price per MWh for both peak and off-peak hours (Exhs. JU-1, at 38; JU-3-A at Exhibit D; JU-3-B at Exhibit D; JU-3-C at Exhibit D). Energy payments begin at $51.51 per MWh in the first year of the PPAs (Exhs. JU-3-A at 75-76; JU-3-B at 84-85; JU-3-C at 75-76). The TSAs provide for a schedule of transmission service payments equal to the unit price per kW-month, beginning at $9.16 per kW-month in the first year of the TSAs, and escalating each contract year (Exhs. JU-1, at 38, JU-4-A at 132-133; JU-4-B at 132-133; JU-4-C at 132-133).

IV. DEPARTMENT REVIEW UNDER SECTION 83D

Pursuant to Section 83D, the Companies must jointly and competitively solicit proposals for clean energy generation resources. Section 83D(a); 220 CMR 24.03. The Department will review the competitive solicitation process to determine whether it was open, fair, and transparent. In addition, the Department will consider whether the Companies evaluated and selected winning bids in a reasonable manner. See e.g., Long-Term Contracts

17 Qualified shortfall energy is hydroelectric energy produced by the Hydro-Québec Power Resources and delivered into New England over any transmission line (Exh. JU-3-A at 17; JU-3-B at 18; JU-3-C at 17).

for Offshore Wind Energy Generation Pursuant to Section 83C, D.P.U. 18-76 through D.P.U. 18-78, at 7 (2019); Three State Request for Proposals, D.P.U. 17-117 through D.P.U. 17-120, at 24-27 (2018).

Provided that reasonable proposals have been received, the Companies must enter into long-term contracts to facilitate the financing of eligible clean energy generation resources. Section 83D(a); 220 CMR 24.03. Therefore, the Department must determine whether each company has demonstrated that the proposed contracts are (1) with an eligible clean energy generating resource and (2) facilitate the financing of that clean energy generating resource.

In addition, Section 83D and the Department's regulations, 220 CMR 24.00, et seq., set forth specific findings that the Department must make in order to approve a long-term contract for clean energy generation. In particular, the Department must determine that the clean energy generating resource (1) contributes to reducing winter electricity price spikes and guarantees energy delivery in winter months; (2) provides enhanced electricity reliability within Massachusetts; (3) avoids line loss and mitigates transmission costs to the extent possible, while ensuring that transmission cost overruns, if any, are not borne by ratepayers; (4) adequately demonstrates project viability in a commercially reasonable timeframe; (5) allows clean energy generation resources to be paired with energy storage systems; and (6) where feasible, creates and fosters employment and economic development in Massachusetts. Section 83D(d); 220 CMR 24.05(1).

The Department must review the potential costs and benefits of such contracts and approve a contract only upon a finding that it is a cost-effective mechanism for procuring low-cost renewable energy on a long-term basis, taking into account the factors outlined in Section 83D. Section 83D; 220 CMR 24.05(1). As part of this analysis, the Department will consider the difference between the contract costs and the market value of the products, as well as other potential economic and environmental benefits to ratepayers. Section 83D(d); 220 CMR 24.05(1).

In our review of a long-term contract for clean energy generation under Section 83D, the Department will also consider whether the contract is in the public interest.[18] See D.P.U. 18-76 through D.P.U. 18-78, at 49; D.P.U. 17-117 through D.P.U. 17-120, at 14; Long-Term Contracts for Renewable Energy, D.P.U. 13-146 through D.P.U. 13-149, at 9 (2014). Further, the Department will consider whether the associated cost recovery method is in the public interest and will result in just and reasonable rates pursuant to G.L. c. 164, § 94. See Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid, D.P.U. 09-138, at 12 (2009); see also Boston Edison Company/ComEnergy Merger, D.T.E. 99-19, at 8 (1999), citing Mass. Oilheat Council v. Department of Public

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18 Pursuant to G.L. c. 164, § 94A ("Section 94A"), an electric or gas distribution company must obtain Department approval to enter into a contract for the purchase of electricity or gas covering a period in excess of one year. The Department has construed our approval under Section 94A to require a determination that the contract is consistent with the public interest. See, e.g., NSTAR Electric Company, D.P.U. 07-64-A at 58 (2008); New England Electric System/Nantucket Electric Company, D.P.U. 95-67, at 21-22 (1995), citing New England Power Company, D.P.U. 1204 (1982). The Department's public interest review in this proceeding will, therefore, satisfy the review otherwise performed under Section 94A.

Utilities, 418 Mass. 798, 804 (1994); Boston Real Estate Bd. v. Department of Public Utilities, 334 Mass. 477, 495 (1956).

V. SOLICITATION PROCESS

A. Introduction

Section 83D requires the Companies and DOER to jointly solicit proposals for clean energy generation resources using a competitive solicitation process. Section 83D(b). To this end, the Companies and DOER developed a Request for Proposals ("RFP") in consultation with the Attorney General. Timetable and Method of Solicitation and Execution of Long-Term Contracts under Section 83D, D.P.U. 17-32, at 25 (2017). On February 2, 2017, the Companies submitted the proposed timetable and method for solicitation and execution of the long-term contracts contained in the RFP for Department review. D.P.U. 17-32, at 1. The Department approved the proposed timetable and method for solicitation and execution of long-term contracts on March 27, 2017. D.P.U. 17-32, at 96-97.

On March 31, 2017, the Companies and DOER issued the RFP to approximately 600 potential bidders, based on a list of entities with an interest in developing clean energy generation projects compiled by the Companies and DOER (Exh. JU-1, at 21). Four types of products were solicited under the RFP: (1) clean energy generation from incremental hydroelectric generation via long-term contract; (2) clean energy generation from new Class I RPS-eligible resources via long-term contract; (3) clean energy generation and Class I Renewable Energy Certificates ("RECs") environmental attributes via long-term contract from a combination of incremental hydroelectric generation and new Class I RPS-eligible resources; and (4) clean energy generation from incremental hydroelectric generation and/or new Class I RPS-eligible resources with Class I RECs and/or environmental attributes via long-term contract with a transmission project under FERC tariff (Exhs. JU-1, at 21-22; JU-2, at 18-21). The RFP allowed for proposals that pair clean energy generation with energy storage systems (Exh. JU-2, at 18).

Prior to bid submission, prospective bidders were allowed to submit written questions pertaining to the RFP (Exh. JU-1, at 22).[19] A total of 46 bids, with 53 distinct proposals, were received (Exh. JU-1, at 22). An evaluation team, made up of employees of the Companies and DOER ("Evaluation Team"), evaluated the bids (Exhs. JU-1, at 23; JU-2, at 5). As described in Section V, below, the project ultimately selected through the solicitation process was the "New England Clean Energy Connect: 100% Hydro" proposal ("NECEC Hydro") that was submitted jointly by Hydro Renewable Energy Inc., an affiliate of Hydro-Québec, and CMP (Exh. JU-1, at 8).

B. Bid Evaluation Process

1. Overview

The RFP specified a three-stage bid evaluation process (Exhs. JU-1, at-23; JU-2, at 17). The first stage ("Stage One") of the process consisted of a review of each proposal's compliance with eligibility and threshold requirements contained in the RFP (Exhs. JU-1,

[19] Bidders submitted approximately 130 questions (Exh. JU-1, at 18).

at 23; JU-2, at 17). The second stage ("Stage Two") of the process consisted of numerical scoring of the quantitative and qualitative factors of each proposal that passed the Stage One review (Exhs. JU-1, at 23; JU-2, at 17). Eligible proposals were evaluated on a 100-point scale, with a maximum of 75 points awarded for quantitative factors and 25 points for qualitative factors (Exhs. JU-1, at 25; JU-2, at 36). The third stage ("Stage Three") of the process consisted of further evaluation of the proposals, including analysis of project portfolios to achieve approximately 9.45 TWh of clean energy generation annually, to ensure selection of viable projects that provide low-cost clean energy generation with limited risk (Exhs. JU-1, at 23; JU-2, at 41-42).

The Evaluation Team retained (1) a consultant to develop and run a simulation model used to quantify estimated benefits and assist in the development of quantitative scores and rankings of bids,[20] and (2) a consultant to analyze the reasonableness of cost estimates in relation to the transmission portion of the bids (Exh. JU-1, at 23). In addition, DOER retained a consultant to assist with bid evaluation (Exh. JU-1, at 23).

The Evaluation Team disqualified 17 bids during Stage One for failing to meet eligibility and threshold requirements (Exh. JU-1, at 24). During Stages Two and Three, the Evaluation Team evaluated all bids that advanced from Stage One (Exh. JU-1, at 23).

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20 The process used by the consultant to develop and run the simulation model is described in Exhibit JU-6.

2. Quantitative Evaluation

As part of the Stage Two quantitative analysis, the Evaluation Team calculated each proposal's costs, direct benefits, and indirect benefits to ratepayers (Exh. JU-1, at 26). The Evaluation Team compared bids using the core measurement of levelized net benefit-per MWh of each proposal, expressed in 2017 dollars (Exh. JU-1, at 25).

The Evaluation Team compared the costs and benefits of the proposals using a simulation model (Exh. JU-1, at 25). The Evaluation Team used the model to simulate the operation of New England wholesale markets for energy and ancillary services, forward capacity, and RECs for both a base case and for each proposal (Exh. JU-6, at 8-9).[21] The Evaluation Team then ran the simulation model to estimate the incremental costs and benefits of each bid relative to a base case (Exh. JU-6, at 82).

In response to the RFP, bidders proposed to sell at least 20 MW of clean energy generation resources from incremental hydroelectric generation and/or new Class I RPS-eligible resources, for contract periods from 15 to 20 years (Exh. JU-2, at 18, 24). Eligible proposals included (1) clean energy generation from incremental hydroelectric generation via long term contract, (2) clean energy generation from new Class I RPS-eligible resources via long term contract, (3) clean energy generation and Class I RECs/environmental attributes via long term contract with a combination of incremental

21 The base case represents a forecast of the New England energy grid without the Section 83D projects in service (Exh. JU-6, at 8, App. 5). The base case is inclusive of all statutory requirements and regulations in effect as of August 11, 2017 (Exh. JU-6, at 83).

hydropower generation and new Class I RPS-eligible resources, and (4) clean energy generation from incremental hydropower generation and/or new Class I RPS-eligible resources with Class I RECs and/or environmental attributes via long term contract with a transmission project under FERC tariff (Exh. JU-2, at 18-21).

In Stage Two, the Evaluation Team modeled small proposals differently from large proposals to allow a fair comparison between the two size categories[22] (Exh. JU-6, at 6). When modeling small proposals, the Evaluation Team chose to run the energy and ancillary service, and forward capacity auction modules on the capacity mix projected in the base case in addition to the small proposal's capacity, rather than on a capacity mix estimated by running the small proposals through the capacity expansion module (Exh. JU-6, at 14).

The Evaluation Team estimated the cost of each proposal using the price inputs for energy, RPS and/or Clean Energy Standard ("CES") compliance, and transmission, including network upgrades (Exh. JU-6, at 4, 28-29). The Evaluation Team assessed the reasonableness of each proposal's bid transmission costs and provided its own transmission cost estimates, where necessary (Exh. JU-6, at 29).

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22 A proposal was classified as small if it would not cause any changes in capacity additions, capacity retirements, or REC prices under the base case (Exh. JU-6, at 14). In this regard, the Evaluation Team determined that a proposal was small if its generation capacity contribution to the ISO-NE installed capacity requirements was less than or equal to 140 MW and its annual generation of RECs or environmental attributes was less than 670 gigawatt-hours ("GWh") (Exh. JU-6, at 14). In addition, certain proposals with installed capacity requirements greater than 140 MW and with REC or environmental attribute generation less than 670 GWh were classified and evaluated as small if they did not affect REC prices (Exh. JU-6, at 14).

The direct benefits of each proposal include the direct benefits of energy, RECs and the environmental attributes used as Clean Energy Certificates ("CECs") for CES compliance (Exh. JU-1, at 27). To calculate the direct benefit of energy, the Evaluation Team used the simulation model to generate the locational marginal price ("LMP") at each bid's delivery node (Exh. JU-6, at 28). The Evaluation Team then estimated the annual market value of energy for each bid on a mark-to-market basis by estimating the revenues generated from the bid after selling the energy on the wholesale market over the contract period (Exh. JU-6, at 28-29). To calculate the direct benefit of RECs and CECs, the Evaluation Team calculated the outstanding Class I RPS and CES compliance requirements for each year and then estimated the direct annual benefit as the avoided cost of RECs and CECs retained for compliance plus the annual benefit of any excess RECs and CECs sold at market price (Exh. JU-6, at 28).[23] The Evaluation Team then calculated the levelized unit net direct benefit for each proposal by calculating the present value of the total direct energy and REC/CEC benefits, minus the present value of the total direct costs, divided by the present value of the annual energy deliveries, expressed in 2017 dollars (Exh. JU-1, at 27).

The Evaluation Team calculated the indirect benefit of each proposal as the sum of the estimates of the indirect benefits of energy, RECs/CECs, compliance with the Global Warming Solutions Act, St. 2008, c. 298 ("GWSA"), and winter price mitigation

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23 The REC price forecast for New England was developed using a capacity expansion module subject to environmental constraints, including each New England state's year-by-year RPS Class I requirements (Exh. JU-6, at 85, 87-90).

(Exh. JU-1, at 27-28). The indirect benefit of energy was based on changes to wholesale energy market costs as a result of adding a bid's energy output to the market (Exh. JU-1, at 27).[24] The indirect benefits of RECs and CECs were calculated as changes to the costs for Class I RECs and CECs as a result of adding a bid's REC and CEC contributions to the market (Exh. JU-1, at 27).[25] The indirect GWSA benefit for each bid was calculated as the incremental value of emissions reductions not yet accounted for through RPS and CES compliance (Exh. JU-1, at 27).[26] Finally, the indirect benefit of winter price mitigation was estimated as the reduction in customers' exposure to extreme winter energy prices with a

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[24] The Evaluation Team calculated changes to wholesale energy market costs as the change in LMP-based total costs to customers between the proposal case and the base case (Exh. JU-6, at 30). LMP-based total costs were calculated as the annual sum of hourly LMPs multiplied by load in each load zone in Massachusetts, adjusted by the proportion of distribution service retail load to total load in each load zone (Exh. JU-6, at 30).

[25] The Evaluation Team calculated the cost changes as the annual quantity of Class I RECs to be acquired to meet RPS standards in excess of the quantity supplied by the bid (the benefits of which are captured in the direct benefits) multiplied by the estimated change in REC price in dollars per MWh between the proposal and the base case (Exh. JU-6, at 30-31).

[26] The Evaluation Team calculated GWSA benefit as a project's incremental greenhouse gas emissions reduction minus total RECs/CECs produced, multiplied by a greenhouse gas compliance value (Exh. JU-6, at 31). The calculation method and compliance value used in the GWSA benefit calculations were developed by DOER (Exh. JU-1, at 27). Although Eversource and Unitil accept DOER's method, National Grid maintains that the estimated greenhouse gas emissions reduction should be treated as a separate metric from the quantity of RECs/CECs produced (Exh. JU-1, at 27; National Grid Supplement to Companies Reply Brief at 2-3). See also D.P.U. 18-76 through D.P.U. 18-78, at 16 n.27.

proposal in service (Exh. JU-1, at 27-28).[27] The Evaluation Team calculated the levelized unit net indirect benefit by calculating the present value of the total indirect benefits divided by the present value of the annual energy deliveries, expressed in 2017 dollars (Exh. JU-1, at 28).

The Evaluation Team then calculated each bid's total levelized unit net benefit, expressed in 2017 dollars per MWh, as the sum of its levelized unit net direct benefit and its levelized unit net indirect benefit (Exh. JU-1, at 28). The Evaluation Team ranked the bids based on their total levelized unit net benefit, with the highest total levelized unit net benefit bid receiving the maximum quantitative score of 75 points (Exh. JU-1, at 28). Finally, the Evaluation Team determined the quantitative score for each remaining bid by (1) calculating the ratio of each bid's levelized unit net benefit to the levelized unit net benefit of the highest ranked bid and (2) multiplying the ratio by 75 (Exh. JU-1, at 28).

3. Qualitative Evaluation

As part of Stage Two, the Evaluation Team performed a qualitative analysis of each proposal (Exh. JU-1, at 25, 29). The Evaluation Team considered statutory and regulatory requirements to identify the projects that were likely to be constructed and provide benefits,

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27 The Evaluation Team calculated a bid's winter price mitigation benefit as the annual change in a proposal's market value of energy in a year with extreme winter prices (Exh. JU-6, at 31-32). Extreme winter-month spot gas price variation was derived using data from 2002 through 2017, based on an assumption that an extreme winter price scenario would occur once in 15 years (Exh. JU-6, at 31-32).

while also supplying a cost-effective means of delivering qualified clean energy (Exh. JU-1, at 29).

The Evaluation Team awarded bids a maximum of 25 points based on eight primary evaluation factors: (1) overall project viability; (2) operational viability; (3) extent to which the project can support the Commonwealth's GWSA requirements; (4) siting, permitting, and project schedule;[28] (5) reliability benefits; (6) benefits, costs, and contract risk; (7) environmental impacts from siting; and (8) economic benefits to the Commonwealth[29] (Exhs. JU-1, at 29-30; JU-2, at 39-41). The Evaluation Team further broke down each factor to assess specific progress commitments and to advance projects that minimized risk and maximized value to customers (Exh. JU-1, at 29-30). To support the scoring, the Evaluation Team developed a qualitative bid evaluation protocol,[30] which identified the criteria used to evaluate the qualitative bid factors and determine the qualitative score and ranking (Exhs. WP Support Tab D; WP Support Tab E).

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28 This factor assessed project feasibility and the ability to obtain financing in order to achieve the commercial operation date (Exh. JU-1, at 29).

29 As required by Section 83D(d), one criterion was the extent to which proposals combine new Class I RPS -eligible resources and firm hydroelectric generation, and demonstrate a benefit to low-income ratepayers in the Commonwealth without adding cost to the project (Exh. JU-2, at 41).

30 A sub-committee of the Evaluation Team developed the factors included in the qualitative evaluation protocol (Exh. JU-1, at 29). The Independent Evaluator reviewed and modified certain aspects of the protocol in consultation with the qualitative sub-committee of the Evaluation Team (Exh. IE Report, at 19-20).

4. Bid Selection

The Evaluation Team added a proposal's quantitative and qualitative points and ranked the proposals from high to low according to a bid's total score (Exhs. JU-1, at 30; JU-6, at 17). The Evaluation Team then determined which proposals would proceed to the Stage Three evaluations based on rank order, cost effectiveness, and total annual MWh/year for each the proposal relative to the 9,450,000 MWh procurement target (Exhs. JU-1, at 30-31. In Stage Three, the Evaluation Team assessed potential portfolio effects and impacts as well as certain other considerations per its discretion as described in the RFP (Exhs. JU-1, at 31-32; JU-2, at 41-42; IE Report at 28-31). The Evaluation Team developed various combinations of top-ranked project proposals, then performed a quantitative analysis and sensitivity analyses on those portfolios (Exh. JU-1, at 31). The Evaluation Team calculated the scores and rankings of the portfolios, then ranked them on both levelized unit net benefit and total net benefit values (Exhs. JU-1 at 31-32; JU-7; JU-8).

At the conclusion of the evaluation process, the "Northern Pass: 100% Hydro" bid ("Northern Pass Hydro") using the Northern Pass transmission project ("Northern Pass") and the NECEC Hydro bid using NECEC emerged as the two top-ranked bids (Exh. JU-1, at 32). A selection team, comprised of representatives from the Companies, failed to reach consensus on the selection of a winning bid (Exh. JU-1, at 32-33). Eversource and Unitil preferred the Northern Pass Hydro bid, while National Grid preferred the NECEC Hydro bid

(Exh. JU-1, at 32).[31] Consistent with the procedure established in Section 83D(c), the Companies notified DOER that they were unable to reach consensus agreement, and each company separately furnished a selection letter summarizing the reasoning for its selection (Exhs. JU-1, at 32; JU-9-A; JU-9-B; JU-9-C; IE Report, at 31-32).

Pursuant to Section 83D(c),[32] DOER, in consultation with the Independent Evaluator, issued a final binding determination selecting Northern Pass Hydro as the winning bid because Northern Pass was projected to be in service two years earlier than NECEC[33] (Exhs. JU-1, at 32-33; JU-10; IE Report at 32-33). However, on February 1, 2018, the New Hampshire Site Evaluation Committee ("NHSEC") voted to deny Northern Pass a necessary permit (Exh. JU-1, at 34). Because the permit denial significantly impacted Northern Pass's ability to deliver the clean energy generation resources within the proposed timeframe, the Companies, with the Independent Evaluator's participation, notified Northern Pass on February 14, 2018, that they would discontinue discussions and cancel Northern Pass's conditional selection if it could not obtain the necessary permit from NHSEC by March 27, 2018 (Exh. JU-1, at 35). Because Northern Pass did not obtain the NHSEC

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31 The NECEC Hydro bid was the top ranked bid in the Stage Three evaluation using real levelized $/MWh. In an alternate ranking using net present value, the Northern Pass Hydro bid was the top ranked bid (Exh. IE Report at 29-30).

32 Pursuant to Section 83D(c), if the Companies are unable to agree on a winning bid, the matter shall be submitted to DOER, which shall, in consultation with the Independent Evaluator, issue a final, binding determination of the winning bid.

33 In addition, Northern Pass had already completed significant elements of its required permitting and interconnection processes (Exhs. JU-1, at 33; JU-10).

permit by that deadline, on March 28, 2018, the Companies terminated contract negotiations with Northern Pass and the NECEC Hydro became the sole project to proceed with contract negotiations (Exh. JU-1, at 35).

C. Independent Evaluator Report

Pursuant to Section 83D(f), the Independent Evaluator is tasked with reviewing the solicitation and bid selection process to ensure that it is fair and transparent, and not unduly influenced by an affiliated company. At the request of DOER, the Independent Evaluator also performed oversight of the contract negotiation process (Exh. IE Report at 2).

The Independent Evaluator concluded that all bids were evaluated in a fair and non-discriminatory manner, and that the Evaluation Team fairly selected NECEC Hydro as the winning bid (Exh. IE Report at 54). The Independent Evaluator concluded that the winning bid was the highest ranking bid in the final evaluation of project portfolios as well as the proposal with the highest net benefits and lowest cost per MWh (in real levelized 2017 dollars) (Exh. IE Report at 55).

D. Positions of Parties

1. RENEW Northeast

RENEW argues that the evaluation process was neither fair nor non-discriminatory because the Evaluation Team excluded stand-alone bids, including the top two ranked bids, from consideration in the final Stage Three evaluation (RENEW Brief at 4). RENEW asserts that these projects were excluded because they did not offer the maximum 9.45 TWh, although this was not a requirement of Section 83D (RENEW Brief at 4).

RENEW asserts that renewable energy projects are competitive with the winning bid's price (RENEW Brief at 4). RENEW further argues that the projects ranked first and second in Stage Two would have remained in those same positions in Stage Three and, but for the Stage Three evaluation protocol requiring bids to supply 9.45 TWh, the NECEC Hydro bid would not have been the top ranked project in Stage Three (RENEW Brief at 4-5).[34]

2. Department of Energy Resources

DOER contends that each proposal went through a rigorous quantitative and qualitative analysis as outlined in the RFP and evaluation protocols (DOER Brief at 12). DOER maintains that, at the conclusion of the quantitative and qualitative analysis, the Evaluation Team determined that NECEC Hydro would provide significant benefits (DOER Brief at 12, citing Exh. JU-7, at 2).

With regard to RENEW's argument regarding stand-alone bids, DOER maintains that RENEW misunderstands the purpose of the portfolio analysis in Stage Three and its impacts on the relative cost-effectiveness of proposals (DOER Brief at 14). DOER maintains that the Evaluation Team followed the RFP requirement to determine which proposals proceed to Stage Three following the Stage Two evaluation based on the following considerations: (1) the rank order of the proposals at the end of the Stage Two evaluation; (2) the cost

34 The Attorney General made a similar argument regarding the ranking of projects generally in Stage Two and Stage Three (Attorney General Brief at 31-34). However, rather than apply her argument to the instant solicitation, the Attorney General characterizes it as a recommendation for future solicitations (see Section XI, below) (Attorney General Brief at 31-34).

effectiveness of the proposals based on the Stage Two quantitative evaluation; and (3) the total annual MWh/year quantities of the proposal(s), relative to the annual procurement target (DOER Reply Brief at 14, citing Exh. JU-2, at 35). DOER contends that the Evaluation Team used combinations of higher-ranked proposals to build the Stage Three portfolios, which included consideration of the top two ranked projects from Stage Two (DOER Reply Brief at 14-15). DOER argues that RENEW's assertion that the Evaluation Team excluded the two top ranked bids at the end of Stage Two from further consideration in final Stage Three evaluation is incorrect because those projects were fully and appropriately evaluated in Stage Three, and at the conclusion of Stage Three, were not the most cost-effective portfolios (DOER Reply Brief at 15).

Moreover, DOER argues that RENEW mischaracterizes that the Stage Two results of multiple projects are not additive and are, therefore, not final (DOER Reply Brief at 15). DOER argues that the Stage Three analysis contained a portfolio effect evaluation so that a project's total, comprehensive cost effectiveness could be determined (DOER Reply Brief at 16). Therefore, DOER argues that the Evaluation Team reasonably conducted the Stage Three analysis (DOER Reply Brief at 16).

3. Companies

The Companies maintain that the PPAs are the result of an open and robust solicitation process (Companies Brief at 20). The Companies further maintain that they carefully evaluated the bids (Companies Brief at 20).

E. Analysis and Findings

In evaluating the competitiveness of a solicitation process, the Department considers whether the process was open, fair, and transparent. D.P.U. 18-76 through D.P.U. 18-78, at 21; D.P.U. 17-117 through D.P.U. 17-120, at 24-27; D.P.U. 13-146 through D.P.U. 13-149, at 26; NSTAR Electric Company, D.P.U. 11-05 through D.P.U. 11-07, at 40 (2011), citing New England Gas Company, D.P.U. 10-114, at 221 (2011); NSTAR Electric Company, D.P.U. 07-64-A at 60-61 (2008) (noting the "Department's fundamental interest in open, competitive, and transparent procurement processes"); Boston Gas Company, Colonial Gas Company, and Essex Gas Company, each d/b/a KeySpan Energy Delivery New England, D.T.E. 04-9, at 10 (2004) (RFP is acceptable if the process was open, fair, and transparent), quoting Natural Gas Unbundling, D.T.E. 98-32-B at 54-55 (1999).

With regard to whether the solicitation was open, the Companies disseminated the RFP to a group of approximately 600 entities with an interest in developing clean energy generation projects based on a list they developed with DOER (Exhs. JU-1, at 21; WP Support Tab A). In response to the RFP, the Companies received 46 bid packages (with 53 distinct proposals) from clean energy generation developers (Exh. JU-1, at 22). Given the broad dissemination of the solicitation to potential bidders and the variety of bids received, the Department finds that the solicitation was open. See D.P.U. 18-76 through D.P.U. 18-78, at 21-22; D.P.U. 17-117 through D.P.U. 17-120, at 24-27.

For the Department to find that the solicitation process was fair and transparent, the Companies must demonstrate that they (1) clearly described the evaluation process to each potential bidder, (2) provided the evaluation criteria in the RFP, and (3) provided an opportunity for bidders to request clarification of the evaluation criteria and the RFP process. D.P.U. 18-76 through D.P.U. 18-78, at 22; D.P.U. 17-117 through D.P.U 17-120, at 27; D.P.U. 13-146 through D.P.U. 13-149, at 27; D.P.U. 11-05 through D.P.U. 11-07, at 42, citing D.P.U. 10-114, at 221; D.P.U. 07-64-A at 60-61 n.21; D.T.E. 04-9, at 10. The Department previously determined that the timetable and method of solicitation described in the RFP was consistent with Section 83D and 220 CMR 24.00, et seq. D.P.U. 17-32, at 96. The RFP clearly identified the criteria that the Companies were to use in each step of the bid evaluation process (Exhs. JU-1, at 19; JU-2, at 11-38). In addition to guidelines provided in the RFP, potential bidders were provided an opportunity to and did submit written questions prior to submitting bids (Exh. JU-1, at 22). Accordingly, the Department finds that the Companies have demonstrated that the solicitation process was fair and transparent. See D.P.U. 18-76 through D.P.U. 18-78, at 22; D.P.U. 17-117 through D.P.U. 17-120, at 26.

Further, with respect to the bid evaluation process, the Department considers whether the Companies evaluated and selected winning bids in a reasonable manner, based on the criteria set forth in the RFP. D.P.U. 18-76 through D.P.U. 18-78, at 22; D.P.U. 17-117 through D.P.U. 17-120, at 24; D.P.U. 13-146 through D.P.U. 13-149, at 26; D.P.U. 11-05 through D.P.U. 11-07, at 40, citing D.T.E. 04-9, at 10; The Berkshire Gas Company, D.T.E. 02-56, at 10 (2002). After screening projects for threshold requirements, the

Evaluation Team conducted a quantitative evaluation of the bids based on the costs of each project as well as the direct and indirect benefits to customers (Exh. JU-1, at 25-30). As a result, the Evaluation Team assigned each bid a quantitative score on a 75-point scale (Exh. JU-1, at 28). We find no merit in RENEW's argument that the Evaluation Team should have evaluated certain projects differently between Stage Two and Stage Three. The Evaluation Team conducted its analysis consistent with the method of solicitation approved by the Department and reflected in the RFP. D.P.U. 17-32, at 96; see also Exh. JU-2, at 41-42.

Next, the Evaluation Team assigned each bid a qualitative score on a 25-point scale, based on an assessment of which projects were most likely to be developed and were a cost-effective means of delivering clean energy generation resources (Exhs. JU-1, at 29; WP Support Tab D). The Evaluation Team combined the quantitative and qualitative scores to rank the projects based on total points (Exh. JU-1, at 30). Finally, the Evaluation Team selected the proposal that would provide the greatest impact and value to ratepayers, consistent with the objectives and requirements of Section 83D (Exh. JU-1, at 30-31).

Based on our review, the Department finds that the quantitative and qualitative bid analyses followed the criteria provided in the RFP (Exhs. JU-1, at 30-31; JU-2, at 36-41). Accordingly, the Department finds that the Companies selected the winning bid in a reasonable manner, consistent with the criteria set forth in the RFP.

VI. SECTION 83D REQUIREMENTS

A. Introduction

Pursuant to Section 83D and 220 CMR 24.00 et seq., the Department is required to make several findings regarding proposed long-term contracts for clean energy generation. As a threshold matter, the Department must find that the proposed contracts facilitate the financing of an eligible clean energy generating resource. In addition, the Department must make determinations regarding whether the resource (1) contributes to reducing winter electricity price spikes and guarantees energy delivery in winter months; (2) provides enhanced electricity reliability within Massachusetts; (3) avoids line loss and mitigates transmission costs to the extent possible, while ensuring that transmission cost overruns, if any, are not borne by ratepayers; (4) adequately demonstrates project viability in a commercially reasonable timeframe; (5) allows clean energy generation resources to be paired with energy storage systems; and (6) where feasible, creates and fosters employment and economic development in Massachusetts. Section 83D(d); 220 CMR 24.05(1). The Department addresses each of these requirements below.

B. Eligibility as Section 83D Clean Energy Generating Resource

1. Introduction

In order to be an eligible clean energy generation resource under Section 83D, the resource must be either (1) firm service hydroelectric generation from hydroelectric generation alone, (2) new Class I RPS-eligible resources that are firmed up with firm service hydroelectric generation, or (3) new Class I RPS-eligible resources.[35] For the purposes of Section 83D, "firm service hydroelectric generation" is defined as "hydroelectric generation provided without interruption for one or more discrete periods designated in a long-term contract, including but not limited to multiple hydroelectric run-of-the-river generation units managed in a portfolio that creates firm service though [sic] the diversity of multiple units." Section 83B; 220 CMR 24.02.

Certain parties argue that the generation resource procured under the PPAs is not eligible under Section 83D because it does not constitute clean energy generation. Other parties argue that the resource does not constitute firm service hydroelectric generation.[36] In addition, parties argue that the RFP effectively modified the statutory definition of eligible generation resource by requiring that any hydroelectric generation be incremental and those modified definitions were improperly omitted from the executed PPAs. The Department addresses these and other eligibility-related issues below.

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35 The RFP incorporates the statutory definitions of eligible clean energy generation resource and firm service hydroelectric generation (Exh. JU-2, at 4, 5).

36 Because it is related to whether the clean energy generation resource guarantees energy delivery in winter months pursuant to Section 83D(d)(5)(vi), the Department addresses whether the clean energy generation resource constitutes firm service hydroelectric generation in Section VI.D, below.

2. Positions of the Parties

a. Attorney General

The Attorney General maintains that the PPAs improperly omit any requirement that contract deliveries must be incremental relative to historical average deliveries to New England (Attorney General Brief at 17-18). The Attorney General argues that the procurement of incremental clean energy generation was clearly specified in the RFP, the RFP submission instructions, and the form PPA provided with the RFP (Attorney General Brief at 18-19).

The Attorney General argues that a fully incremental PPA would reflect total deliveries of 24.35 TWh (9.55 TWh of contract energy plus 14.8 TWh of baseline hydroelectric generation) (Attorney General Brief at 20). However, the Attorney General argues that Exhibit H of the negotiated PPAs allows zero percent of the contract energy to be above the historical average for Eversource and Unitil, and, at most 44 percent of the contract energy to be above the historical average for National Grid (Attorney General Brief at 20). The Attorney General claims that the terms of the Eversource and Unitil PPAs could allow Hydro-Québec to decrease its overall imports into New England, relative to the historical average specified in the RFP, and still be entitled to full payment under the contracts (Attorney General Brief at 20).

The Attorney General argues that the Department should require the Companies to modify the PPAs to require the delivery of incremental hydroelectric energy (Attorney General Brief at 26, 29-30). In this regard, the Attorney General recommends that the

Department require HQUS and the Companies to amend Exhibit H in each PPA to require a minimum baseline hydroelectric generation value of 14.8 TWh (i.e., the historical average specified in the RFP, included in the NECEC Hydro bid, and relied upon during bid evaluation and selection) (Attorney General Brief at 26).

b. Department of Energy Resources

DOER urges the Department to approve the PPAs as filed because Section 83D does not require the contracts to guarantee delivery of a historical level of electricity into the region above the statutorily mandated amount of 9.45 TWh (DOER Reply Brief at 4-5). In this regard, DOER argues that the term "incremental hydroelectric generation" as used in the RFP was intended to ensure that bidders had sufficient capacity to supply clean energy generation above their historical three-year average sales into ISO-NE and not to require bidders to guarantee their historical deliveries over a 20-year period (DOER Reply Brief at 4, 6-7). In addition, DOER submits that the historical import assumptions used to build the evaluation model were neither a benchmark nor a requirement for the PPAs (DOER Reply Brief at 6).

DOER objects to the Attorney General's characterization of Exhibit H as evidence that the RFP requires the PPAs to ensure delivery of the entirety of Hydro-Québec's historical three-year average hydroelectric sales in the ISO-NE region above the energy associated with the NECEC Hydro bid, for a term of 20 years (DOER Reply Brief at 4, 7-8). Instead, DOER contends that Exhibit H provides additional protections to ratepayers in the form of penalties to HQUS when non-contracted hydroelectric energy deliveries into ISO-NE fall below a negotiated, commercially reasonable standard (DOER Reply Brief at 7-8).

DOER contends that if the PPAs are approved, NECEC Hydro will provide the Commonwealth with 9.55 TWh of clean energy generation and associated environmental attributes (DOER Brief at 5). With regard to whether the resource qualifies as a clean energy generating resource under Section 83D, DOER represents that NECEC Hydro is projected to provide 36.61 million metric tons of carbon dioxide equivalents ("MMTCO2e") more emissions reductions than the base case (DOER Brief at 8). Regarding the tracking of environmental attributes, DOER asserts that all bidders were required to use an appropriate tracking system to ensure a unit-specific account of the delivery of clean energy to enable an accurate measurement of progress in achieving the Commonwealth's GWSA goals (DOER Reply Brief at 11). DOER contends that the PPAs appropriately specify that the NEPOOL GIS unit-specific tracking system will be used to ensure that any contract energy (including any allowable shortfall energy) is associated with a hydroelectric attribute (DOER Reply Brief at 11). Finally, DOER asserts that all energy under the PPAs will be qualified clean energy from hydroelectric generation resources, which must be tracked on a generating unit-specific basis (DOER Reply Brief at 11).

c. Conservation Law Foundation

CLF contends that the PPAs do not adequately ensure that the qualified clean energy delivered will be fully incremental, as required by the RFP (CLF Reply Brief at 2). To address this issue, CLF recommends that the Department require the Companies and HQUS to amend Exhibit H of each PPA to include a minimum baseline value of 14.8 TWh (CLF Reply Brief at 2-3).

Concerns about incrementality notwithstanding, CLF maintains that the PPAs will reduce the Commonwealth's statewide Greenhouse Gas ("GHG") emissions by approximately 1.8 MMTCO2e each year, which will aid efforts to achieve GWSA-mandated emissions reductions (CLF Brief at 7-8). CLF observes that the Evaluation Team appropriately used the general principles and method for calculating incremental contribution to GWSA compliance provided by the DOER (CLF Brief at 7). CLF asserts that the Department should reject claims that (1) express concern that the PPAs might result in flat or elevated regional or extra-regional emissions that are not GWSA-jurisdictional "statewide GHG emissions" or (2) suggest that compliance with the GWSA can only credibly be measured "globally" rather than by the GHG inventory (CLF Brief at 8). CLF contends that these claims are speculative, unsupported by evidence, and are the same kind of claims previously rejected by the Supreme Judicial Court as invalid compliance (CLF Brief at 8, citing New England Power Generators Association, Inc. v. Department of Environmental Protection, 480 Mass. 398, 408-410 (2018)).

d. Sierra Club

Sierra Club urges the Department to reject the PPAs (Sierra Club Brief at 7). Sierra Club argues that, although the Department has emphasized the importance of hydroelectric generation being incremental to historical or otherwise expected deliveries, the PPAs lack an incrementality requirement (Sierra Club Brief at 7, citing D.P.U. 17-32). Sierra Club maintains that mandating incrementality for hydroelectric generation is necessary (1) to ensure fairness and symmetry across different types of resources, and (2) to justify the financial outlay asked of Massachusetts ratepayers under the PPAs (Sierra Club Brief at 7-8). Sierra Club argues that the PPAs rely on a concept of incrementality based on HQUS' capability to deliver energy above the level of historical deliveries, which the Department rejected in D.P.U. 17-32 (Sierra Club Brief at 8-9). More specifically, Sierra Club argues that the Companies incorrectly modeled the benefits of HQUS' proposed deliveries as though they were incremental to actual historical import levels and not to the minimum baselines in the PPAs (Sierra Club Brief at 10-11). Furthermore, Sierra Club maintains that the Companies failed to incorporate meaningful safeguards in the PPAs to ensure that the generation being procured is incremental to what Hydro-Québec has been, and is, reasonably expected to be importing into New England in the future absent NECEC (Sierra Club Brief at 11).

Sierra Club argues that because the PPAs fail to require the imported generation to be incremental, the Companies cannot ensure an environmental benefit to ratepayers in Massachusetts (Sierra Club Brief at 12-13). Sierra Club contends it is inappropriate to base claimed GHG emissions reduction benefits on the model used by the Evaluation Team because that the model looked at the bids, which contained an incremental requirement that was not in the final PPAs (Sierra Club Reply Brief at 5). Further, Sierra Club disagrees with intervenors who argue that the contracts will facilitate accounting compliance with the GWSA for the following two reasons: (1) the argument overlooks Section 83D, which requires an environmental benefit beyond the ability of Massachusetts to take accounting credit for otherwise-occurring GHG emission reductions; and (2) flaws in the structure of the PPAs undercut the ability of Massachusetts to take credit for GHG emissions reductions, even on paper (Sierra Club Reply Brief at 6). Sierra Club concludes that the proposed PPAs allow HQUS to re-label existing non-firm deliveries as firm sales at a premium price and fail to guarantee an environmental benefit commensurate with the cost (Sierra Club Brief at 13).

e. NextEra Energy Resources

NextEra contends that the Department has found that a failure to require incremental hydroelectric generation would be a risk to ratepayers as they would be paying for a net increase in MWh per year, but not receiving that service (NextEra Brief at 10, citing D.P.U. 17-32). NextEra argues that the Companies have failed to show that it was appropriate to release HQUS from the obligation in the RFP to deliver fully incremental hydroelectric generation as measured against its three-year historical average (NextEra Brief at 10). NextEra further argues that the Eversource and Unitil PPAs allow HQUS to deliver below its historical average (NextEra Brief at 11).

NextEra argues that the Attorney General's proposed revisions to Exhibit H are insufficient to ensure that the Commonwealth receives fully incremental hydroelectric energy (NextEra Reply Brief at 2). NextEra asserts that it is preferable to revert to a firm requirement for incremental hydroelectric energy, rather than accept the Attorney General's proposed modifications to Exhibit H (NextEra Reply Brief at 2).

NextEra maintains that the Companies failed to appropriately address the impact of the decision to remove the definition of incremental hydroelectric generation from the PPAs on the bid evaluation process (NextEra Brief at 11). In particular, NextEra claims that, based on the RFP, the evaluation of the bids assumed HQUS would be obligated to provide fully incremental energy (NextEra Brief at 11-12). NextEra argues the change to the incrementality requirement negatively impacted the claimed price suppression benefits, including winter price spike suppression, associated with NECEC (NextEra Brief at 11-12). NextEra further asserts that the reductions in GHG and price suppression benefits negatively impact the cost-benefit ratio of NECEC Hydro (NextEra Brief at 12). NextEra concludes that, because the Companies did not ask the Evaluation Team re-run its model using the revised requirements for energy deliveries under the PPAs, the Companies can only speculate as to whether NECEC Hydro would still have been selected as the winning bid (NextEra Brief at 12-13).

In addition, NextEra alleges that the PPAs do not comply with the statutory definition of clean energy generation, which requires the contract energy to come from firm hydroelectric energy alone (NextEra Brief at 3-5). NextEra claims that, while the Hydro-Québec system is predominantly hydroelectric, more than five percent of the Hydro-Québec system mix is wind, biomass, biogas, waste and solar, with some nuclear and fossil fuel generation (NextEra Brief at 3 & n.5, citing Exh. EDC-NEER, Att. 3, at 1-2). NextEra also argues that the Companies have conducted no analysis of whether the hydroelectric facilities listed in Exhibit A of the PPAs are deliverable to the Hydro-Québec

TransEnergie converter substation, which NextEra concludes is further evidence that the NECEC Hydro proposal and associated PPAs are inconsistent with the statutory definition of clean energy generation because the Companies cannot ensure that the delivered energy will come from hydroelectric generation alone (NextEra Brief at 5-6).

NextEra argues that, without the relocation of the Hydro-Québec TransEnergie converter substation to directly connect to hydroelectric energy and deliver over NECEC, the NEPOOL GIS tracking system will not track the use of hydroelectric energy alone (NextEra Brief at 8). NextEra contends that the GIS tracking system will only show that Hydro-Québec hydroelectric facilities were producing energy at the same time deliveries over NECEC were occurring (NextEra Brief at 8). NextEra maintains that because Hydro-Québec has more than 36,000 MW of installed hydroelectric capacity, there will always be more than 9.45 TWh of hydroelectric energy flowing through Hydro-Québec hydroelectric facilities (NextEra Brief at 8). NextEra argues that this type of energy tracking does not satisfy the purpose of the GWSA, which is to show a reduction in GHG emissions and not simply the tracking of the status quo production of hydroelectric energy (NextEra Brief at 8).

NextEra also argues that changes made during contract negotiations to material terms in the RFP, including terms implicating incremental hydroelectric generation, sufficiently deviate from the requirements of the RFP to create new threshold RFP requirements (NextEra Brief at 22-24). For this reason, NextEra argues that the PPAs should be rejected (NextEra Brief at 25).

Finally, NextEra disagrees with CLF, CMP, and DOER that the PPAs will reduce the Commonwealth's GHG emissions by approximately 36 MMTCO2e (NextEra Reply Brief at 3). NextEra argues that the record on GHG emissions reductions that would be achieved is speculative given that the Evaluation Team's calculation of GHG emissions was based on the delivery requirements of the form PPA and not the actual PPAs (NextEra Reply Brief at 4).

f. New England Power Generation Association

NEPGA contends that the Department should reject the PPAs because they do not comply with Section 83D, the Department's directives in D.P.U. 17-32, or the RFP (NEPGA Brief at 9; NEPGA Reply Brief at 7). First, NEPGA argues that the proposed PPAs do not satisfy the RFP requirement that the contracts must guarantee procurement of incremental hydroelectric generation (NEPGA Brief at 7-9). NEPGA maintains that the PPAs will not result in the guaranteed procurement of incremental hydroelectric generation because (1) all of the Hydro-Québec resources from which qualified clean energy will be procured already exist and are operational; (2) Hydro-Québec already imports 15.2 TWh of electricity from its hydroelectric resources into the ISO-NE market on an annual basis; and (3) the PPAs define baseline hydroelectric generation (above which contract deliveries constitute incremental hydroelectric generation) as 3.00 TWh per year for Eversource and Unitil, and 9.45 TWh per year for National Grid (NEPGA Brief at 7-9).

NEPGA further contends that neither Hydro-Québec nor the Companies will have the ability to determine the identity of the specific resources that produce the electric energy that the Companies will purchase under the PPAs in order to demonstrate that the generation purchased did not result from "resource shuffling" within the Hydro-Québec system (NEPGA Brief at 11; NEPGA Reply Brief at 11-12). As a result, NEPGA claims that the PPAs do not provide guaranteed environmental benefits in the form of GHG emissions reductions in a manner that is cost-effective to ratepayers in Massachusetts (NEPGA Brief at 12).

g. Acadia Center

Acadia Center argues that the PPAs inappropriately do not require deliveries to be incremental to historical HQUS deliveries to New England (Acadia Center Reply Brief at 5). In particular, Acadia Center argues that (1) the Eversource and Unitil PPAs allow for zero percent of the contract energy to be above the historical average and (2) the National Grid PPAs allow for at most 44 percent of the contract energy to be above the historical average (Acadia Center Reply Brief at 5). Acadia Center contends that this potential for a decrease in overall imports into New England is inconsistent with the intent of Section 83D (Acadia Center Reply Brief at 6).

Acadia Center argues that the Evaluation Team assumed full incrementality when modeling contract benefits and, therefore, such benefits should be disregarded because they do not reflect the proposed PPAs (Acadia Center Reply Brief at 6). Acadia Center also maintains that there are no environmental benefits to shifting GHG emissions of existing generation from one jurisdiction's GHG balance sheet to another and expresses concerns about the tracking of environmental benefits due to potential leakage (Acadia Center Reply Brief at 7).

In order to address concerns that the proposed PPAs do not require the purchase of incremental energy and fail to ensure environmental benefit in the form of actual GHG emission reductions, Acadia Center argues that Hydro-Québec should be required to document, monitor, and affirm the incrementality of energy deliveries and GHG emission impacts (Acadia Center Reply Brief at 8). Acadia Center notes that, while there are many examples in New England and elsewhere of tools in use to prevent attribute double-counting and leakage, Hydro-Québec currently has no such comprehensive, system-wide tracking tool that would allow for the verification of the regional GHG emission benefits of the proposed PPAs (Acadia Center Reply Brief at 8-9). Acadia Center contends that the ideal outcome would be for Québec to implement a comprehensive GIS attribute tracking system (Acadia Center Reply Brief at 9). In the absence of a GIS equivalent in Québec, Acadia Center maintains that a public disclosure label for the energy under the PPAs "will go a significant way to addressing these concerns" (Acadia Center Reply Brief at 9).

Finally, Acadia Center recommends that the Department mandate a stakeholder-driven process to develop a system to verify that energy deliveries under the proposed PPAs are incremental and confirm regional GHG emission reductions (Acadia Center Reply Brief at 8-9). Acadia Center argues that this would satisfy the Section 83D(j) requirement for a tracking mechanism that accurately measures the progress of achieving GWSA goals (Acadia Center Reply Brief at 9).

h. Western Massachusetts Industrial Group

WMIG argues that the proposed PPAs do not meet the definition of incremental hydroelectric generation in Section 83D (WMIG Reply Brief at 5 citing Attorney General Brief at 18-25). However, WMIG does not endorse the Attorney General's proposed changes to Exhibit H of the contracts to address the incremental issue (WMIG Reply Brief at 6). Instead, WMIG urges the Department to otherwise modify the PPAs to make them consistent with the RFP definition of incremental hydroelectric energy and, thereby, address any impediment that diminishes the benefits of the PPAs for ratepayers (WMIG Reply Brief at 6).

i. RENEW Northeast

RENEW argues that it is unclear whether the Companies are claiming that HQUS will be able to deliver fully incremental hydroelectric generation as specified in the RFP (RENEW Brief at 7, citing Exh. AG-DM-Rebuttal-1, at 14). RENEW also argues that allowing HQUS to proceed to contract negotiations with a less burdensome definition of incremental hydroelectric generation than other bidders was unfair (RENEW Brief at 5-8).Further, RENEW argues that it is unfair for Massachusetts customers to pay for incremental clean energy generation when they could receive substantially less (RENEW Brief at 8).

j. H.Q. Energy Services (U.S.)

HQUS disputes that the PPAs do not procure incremental hydroelectric generation, and it contends that such arguments ignore that the RFP's definition of incremental hydroelectric generation gave the Companies discretion to consider the "otherwise expected delivery" as opposed to the three-year historical average deliveries in qualifying a bid resource (HQUS Reply Brief at 2-3). HQUS contends that the Department has already rejected the argument that the term "incremental hydroelectric generation" should be limited to a comparison with the three-year historical average delivery (HQUS Reply Brief at 3-4 citing D.P.U. 17-32, at 31, 33). Specifically, HQUS maintains that in D.P.U. 17-32, at 31, 33, the Department found that the Companies "appropriately applied discretion when determining that hydroelectric generation should be incremental" (HQUS Reply Brief at 4). HQUS further maintains that, given the fact that Hydro-Québec has vast hydroelectric generation resources that are significantly in excess of what is needed to deliver both the guaranteed qualified clean energy and the three-year historical average deliveries, the Companies reasonably concluded that the energy to be delivered over NECEC qualifies as incremental hydroelectric generation under the RFP (HQUS Reply Brief at 5).

HQUS contends that the Department did not specify how the Companies were to ensure that the contracted qualified clean energy generation, as defined in PPAs, would be incremental to HQUS' "otherwise expected delivery" (HQUS Reply Brief at 6). HQUS alleges that the shortfall damages provisions of Exhibit H create additional economic incentives that will produce imports over existing transmission lines that will be greater than otherwise expected in the absence of the NECEC Hydro contracts (HQUS Reply Brief at 7).

HQUS recommends that the Department reject the Attorney General's proposed modifications to Exhibit H of the PPAs with regard to incremental hydroelectric generation, because the modifications are not straightforward (HQUS Reply Brief at 7). HQUS further argues that each of the Attorney General's suggested modifications would represent a material change to the negotiated balance of interests in the PPAs (HQUS Reply Brief at 7). HQUS adds that reopening negotiations would lead to uncertain results (HQUS Reply Brief at 8).

In response to the Attorney General's proposal to establish a "minimum baseline hydro" value, HQUS argues that this change would materially alter the risk profile of the PPAs in a way that is not accounted for in the NECEC Hydro bid price (HQUS Reply Brief at 9). HQUS claims that it would be inappropriate for the Department to mandate any specific level of energy deliveries for the purpose of calculating damages, as it would be impossible to negotiate the necessary adjustments to approximate HQUS' otherwise expected deliveries (HQUS Reply Brief at 9-10).

In response to the Attorney General's request to eliminate adjustments to reduce the required baseline imports due to low-price on-peak hours, HQUS argues that it would be improper to remove economic considerations from the negotiated cover damages formula because such considerations were explicitly required in the RFP (HQUS Reply Brief at 10). HQUS asserts that it is not required to deliver qualified clean energy when LMPs are likely to become negative, and forcing additional HQUS deliveries during low-price hours could potentially cause other clean energy resources that participate in the market as price takers to stop delivering in response to such market conditions (HQUS Reply Brief at 10).

Finally, HQUS disputes NextEra's argument that because the NEPOOL GIS tracking system will not track the use of hydroelectric energy alone, the PPAs do not comply with the statutory definition of clean energy generation (HQUS Reply Brief at 10-11). Instead, HQUS argues that, under NEPOOL GIS rules, HQUS' imports of unit energy will be properly accounted for (HQUS Reply Brief at 12).

k. Central Maine Power Company

CMP maintains that NECEC Hydro will result in significant incremental hydroelectric generation from existing and new resources in Québec and, therefore, will result in reductions to overall GHG emissions through corresponding reductions of fossil fuel generation in the region (CMP Reply Brief at 9). CMP argues that because HQUS and the Companies entered into firm contracts that require HQUS to deliver the energy except in events of force majeure, the energy will be incremental (CMP Reply Brief at 9). CMP further argues that NECEC will provide increased transmission capability to ensure delivery of the incremental generation to the region (CMP Brief at 5).

l. Companies

The Companies maintain that the PPAs comply with the statutory definitions of "clean energy generation" and "firm service hydroelectric generation" that the Department adopted in its regulations (Companies Reply Brief at 3, citing 220 CMR 24.02). The Companies argue that there are several key provisions in the PPAs that ensure the Companies are purchasing qualifying clean energy generation and associated environmental attributes (Companies Reply Brief at 4). In this regard, the Companies argue that NextEra inaccurately describes the definition of Hydro-Québec Power Resources under the PPAs, and the Companies note that the definition includes Exhibit A, which identifies each of the 62 hydroelectric facilities that make up the Hydro-Québec Power Resources (Companies

Reply Brief at 4-5). The Companies also maintain that HQUS is required to physically supply qualified clean energy to the delivery point at the Larrabee Road substation and transfer that energy into the respective electric distribution company's ISO-NE account, as settled at the delivery point (Companies Reply Brief at 5). The Companies contend that they are not required to pay for generation that is not physically delivered to the delivery point or energy delivered in excess of that generated by the specific Hydro-Québec power resources (Companies Reply Brief at 5). Lastly, in response to NextEra's argument that more than five percent of Hydro-Québec's system mix is wind, biomass, biogas, waste, and solar, with some nuclear and fossil fuel generation, the Companies argue that NextEra's own exhibits demonstrate that Hydro-Québec's sources of energy supply are composed of more than 98 percent renewable resources (Companies Reply Brief at 6 citing Exhs. EDC-NEER-1-2-3 Att.; EDC-RB-1, at 15; HQUS Brief at 9). The Companies contend that because the statutory definition of clean energy generation includes new Class I RPS-eligible resources that are firmed up with firm service hydroelectric generation, the PPAs do not run afoul of the definition of clean energy generation (Companies Reply Brief at 6-7).

The Companies allege that the NECEC Hydro bid complied with the requirements of the RFP because the Department accepted the definition of "incremental hydroelectric generation" as proposed by the Companies and DOER in D.P.U. 17-32 (Companies Reply Brief at 7, citing D.P.U. 17-32, at 33). The Companies maintain that the Department recognized that the baseline energy deliveries used to determine whether energy is incremental might be different from actual deliveries in one or more years (Companies Reply Brief at 7).

Furthermore, the Companies argue that HQUS's affiliate, Hydro Renewable Energy, Inc. ("HRE"), confirmed that deliveries over NECEC will represent incremental hydroelectric generation that could not otherwise have been delivered as clean energy generation to New England without the increased transfer capability between Québec and New England to be provided by NECEC (Companies Reply Brief at 8, citing Exhs. EDC-RB-1, at 18-19; EDC-RB-4, at 18-19; DPU 3-6). The Companies maintain that HRE also represented that additional hydroelectric generating stations, both completed and under construction, will increase the annual production capability of the Hydro-Québec system (Companies Reply Brief at 8 citing Exh. EDC-RB-1, at 19, 20; Tr. 1, at 28).

The Companies claim that the baseline hydroelectric provisions in Exhibit H provide greater protections to customers because they include an enforcement mechanism that is not in the RFP or form PPA (Companies Reply Brief at 10, 12 citing Exh. EDC-RB-1, at 21). The Companies argue that subjecting HQUS to penalties if it fails to maintain a minimum level of baseline hydroelectric generation delivered into New England appropriately protects customers against the risk of paying for a net increase in hydroelectric generation that is not delivered (Companies Reply Brief at 10). By contrast, the Companies contend that the form PPA did not include any provisions for tracking HQUS' baseline deliveries into New England nor did it include any penalties should HQUS fail to maintain deliveries representing a net increase in MWh per year as compared to what would have been expected without the PPAs (Companies Reply Brief at 11).

The Companies represent that the minimum required baseline hydroelectric generation import levels established to measure damages are the result of reasonable, good-faith negotiations between the Companies and HQUS (Companies Reply Brief at 11). The Companies argue that to arrive at the appropriate level of penalties and incentives, the Companies and HQUS negotiated acceptable levels of minimum required baseline hydroelectric generation imports (Companies Reply Brief at 14). The Companies assert that these baselines (1) account for future uncertainties, while still providing HQUS with a strong incentive to import hydroelectric generation into New England in addition to the contract quantities of 9.55 TWh, and (2) protect Massachusetts customers against the risk of paying for NECEC without receiving a net increase in annual MWh of clean hydroelectric generation (Companies Reply Brief at 14). Furthermore, the Companies maintain that there is no evidence to suggest that HQUS will decrease its other imports to New England as a result of these PPAs (Companies Reply Brief at 12).

The Companies assert that the Attorney General's recommended changes to Exhibit H are unreasonable because the changes will jeopardize the important economic and environmental benefits provided by the PPAs (Companies Reply Brief at 15-16). In particular, the Companies argue that changing a material provision of the PPAs would reopen contract negotiations, potentially resulting in consequences that are not beneficial to customers (Companies Reply Brief at 16). Further, the Companies argue that the PPAs may only be amended by written agreement of the contract parties, and HQUS would not be obligated to accept the amendments proposed by the Attorney General, even if the Department were to order such revisions (Companies Reply Brief at 16, citing Exhs. JU-3-A at 62; JU-3-B at 70; JU-3-C at 62).

In response to intervenors' arguments that the modeled GHG and GWSA results are not reliable, the Companies contend that the bid evaluation model appropriately used historical schedules of energy from Hydro-Québec in 2012 and reasonably assumed the same hourly schedule would persist in the future (Companies Reply Brief at 27). The Companies assert that the Evaluation Team did not model deliveries equal to the minimum required baseline hydroelectric generation imports because the minimum required baseline hydroelectric generation imports quantities do not reflect the average level of expected deliveries over the 20-year term of the PPAs (Companies Reply Brief at 27).

The Companies also dispute certain intervenors' "resource-shuffling" arguments (Companies Reply Brief at 28). First, the Companies assert that the PPAs require a unit-specific accounting of all energy and environmental product sales to demonstrate that the Companies are purchasing only qualified clean energy generation from the specified Hydro-Québec power resources in Exhibit A of the PPAs (Companies Reply Brief at 28). The Companies contend that the energy must be tracked in the NEPOOL GIS, and this unit-specific accounting arrangement will be sufficient for purposes of complying with the CES (Companies Reply Brief at 29). The Companies also note that they are not obligated to accept or pay for any environmental attributes that are not associated with the specified MWh of generation from qualified clean energy generation units (Companies Reply Brief at 29).

Finally, the Companies maintain that the framework of the GWSA is solely Massachusetts-specific and note that the Supreme Judicial Court has rejected arguments that regulations passed under the GWSA need not achieve GHG reductions specific to the Commonwealth (Companies Reply Brief at 30-31, citing 474 Mass. at 298 n.25). As to claims of "emissions leakage," the Companies note that the Supreme Judicial Court has rejected arguments that regulations were arbitrary and capricious where they may cause modest emissions leakage because those regulations must be read in concert with the CES, which was intended to work together with the cap regulations to maximize reductions in GHG emissions (Companies Reply Brief at 30-31, citing 480 Mass. at 409). The Companies argue that the PPAs are an important step toward meeting the CES regulations and GWSA goals (Companies Reply Brief at 31-32). The Companies conclude that this procurement, which will be used for CES compliance, will increase competition to build new renewable energy resources to meet the growing demand in Massachusetts and in the region (Companies Reply Brief at 32).

m. Independent Evaluator

The Independent Evaluator reports that during negotiations, National Grid wanted to obtain a contractual commitment from HQUS to deliver additional hydroelectric energy in addition to the PPA amounts (Exh. IE Report at 51). The Independent Evaluator further reports that Unitil, Eversource, and DOER did not agree that the RFP or form PPA required the type of delivery commitment that National Grid was seeking (Exh. IE Report at 51). The Independent Evaluator maintains that it cautioned the Companies that imposing a major obligation or liability on a bidder that was not contemplated by the form PPA and was not included within the scope of a bidder's proposal raises a fairness question but notes that whether proposed imports would be incremental to other deliveries was a matter for the Department to determine (Exh. IE Report at 51-52).

Under the circumstances, the Independent Evaluator maintains that it advised National Grid that it was acceptable to seek a contractual commitment from HQUS for additional hydroelectric energy but cautioned that it must be pursued in a manner that would not cause a collapse of negotiations (Exh. IE Report at 52). The Independent Evaluator concludes that the Companies fairly negotiated the terms of the PPAs and TSAs, consistent with the requirement of the RFP, and that the resulting contracts were no more adverse to the Companies than the bid and, in many cases, more favorable to ratepayers (Exh. IE Report at 54).

3. Analysis and Findings

a. Introduction

In order to be an eligible clean energy generation resource under Section 83D and 220 CMR 24.02, a proposal must be one of the following: (1) firm service hydroelectric generation from hydroelectric generation alone; (2) new Class I RPS-eligible resources that are firmed up with firm service hydroelectric generation; or (3) new Class I RPS-eligible resources. Section 83B; 220 CMR 24.02. For the purposes of Section 83D, firm service hydroelectric generation is "hydroelectric generation provided without interruption for one or more discrete periods designated in a long-term contract, including but not limited to multiple hydroelectric run-of-the-river generation units managed in a portfolio that creates firm service though [sic] the diversity of multiple units." Section 83B; 220 CMR 24.02.

The Companies and DOER issued an RFP and solicited proposals from four categories of generation: (1) clean energy generation from incremental hydroelectric generation via long-term contract; (2) clean energy generation from new Class I RPS-eligible resources via long-term contract; (3) clean energy generation and Class I environmental attributes/RECs via long-term contract from a combination of incremental hydropower generation and new Class I RPS-eligible resources; and (4) clean energy generation from incremental hydropower generation and/or new Class I RPS-eligible resources with Class I environmental attributes and/or RECs via long-term contract with a transmission project under a FERC tariff (Exh. JU-2, at 18-21). The RFP defined "incremental hydroelectric generation" as firm service hydroelectric generation[37] that represents a net increase in MWh per year of hydroelectric generation from the bidder and/or affiliate as compared to the three-year historical average and/or otherwise expected delivery of hydroelectric generation from the bidder and/or affiliate within or into the New England control area (Exh. JU-2,

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37 The definition of "firm service hydroelectric generation" in the RFP is consistent with the statutory definition in Section 83B (Exh. JU-2, at 5).

at 5).[38] The same definition of "incremental hydroelectric generation" was included in the form PPAs[39] that the Companies made available to bidders.

NECEC Hydro bid under the fourth bid category (i.e., to provide clean energy generation from incremental hydropower generation and/or new Class I RPS-eligible resources with Class I environmental attributes and/or RECs via long-term contract with a transmission project under a FERC tariff) (Exh. JU-1, at 8, 44). Consistent with that bid category's requirements, NECEC Hydro represented in its bid proposal that it could comply with the RFP's definition of incremental hydroelectric generation (Exh. JU-2, at 17-20).

On February 14, 2018, the Companies initiated negotiations for PPAs and TSAs with HQUS and CMP, respectively, pursuant to the winning NECEC Hydro bid (Exh. JU-1, at 35). Those negotiations concluded with the execution of signed PPAs and TSAs on June 13, 2018, and the filing of the contracts with the Department for review on July 23,

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38 In its review of the timetable and method of solicitation for the instant procurement, the Department determined that it was appropriate to include a definition of "incremental hydroelectric generation" in the RFP. D.P.U. 17-32, at 33.

39 The form PPA included the following condition: "This draft [PPA] for firm qualified clean energy from hydroelectric generation is intended to provide a general description of the terms to which the [Companies] are willing to agree. The final agreement will be subject to negotiations with the individual electric distribution companies and will be customized to address the relevant circumstances, such as different generating technologies and purchases of an entitlement to all environmental attributes produced by the generating facility, as well as rules specific to purchases and sales from adjacent control areas, as applicable. Accordingly, certain provisions in the final Agreement may differ from this draft Agreement." The Companies maintain a website dedicated to the Section 83D solicitation on which they make available pertinent information, including form PPAs. The website is available at: https://macleanenergy.com/83d/83d-documents/.

2018 (Exhs. JU-3-A at 7; JU-3-B at 7; JU-3-C at 7). The executed PPAs do not contain the defined term "incremental hydroelectric generation" as it appeared in the form PPA (see Exhs. JU-3-A at 7-20; JU-3-B at 7-20; JU-3-C at 7-20). However, the PPAs include the following language in the preamble: "the output of the Hydro-Québec Power Resources, delivered through the New Transmission Facilities (as defined herein), shall constitute incremental hydroelectric generation during the Services Term (as defined herein)" (Exhs. JU-3-A at 7; JU-3-B at 7; JU-3-C at 7).

The Companies state that, under currently effective conditions (i.e., the absence of the PPAs and the transmission capacity provided by NECEC), they expect HQUS's non--firm deliveries to continue in the historical range of between 9.45 TWh and 18 TWh annually (Tr. 2, at 204, 208).[40] Pursuant to the PPAs, HQUS will be required to deliver 9.55 TWh of firm clean energy generation and associated environmental attributes annually to the Companies (Exh. JU-1, at 36). The PPAs refer to the firm clean energy generation as "incremental hydroelectric generation" because it represents an increase over the amount of hydroelectric generation that HQUS would expect to deliver into New England in the absence of the PPAs and the increased transmission capacity provided by NECEC (Exhs. JU-1, at 36; JU-3-A at 7; JU-3-B at 7; JU-3-C at 7).

Intervenors have raised several arguments regarding whether the hydroelectric generation in the PPAs is an eligible resource under Section 83D. In particular, certain

[40] The Companies state that HQUS's non-firm hydroelectric delivery was in this range over the past ten years (Tr. 2, at 308).

intervenors argue that (1) the hydroelectric generation fails to comply with the statutory definition of clean energy generation; (2) the hydroelectric generation fails to comply with the statutory definition of firm service hydroelectric generation;[41] (3) the PPAs fail to use an appropriate tracking system to ensure a unit-specific accounting of the clean-energy delivery; (4) the hydroelectric generation will not be incremental, as the PPAs fail to comply with the requirements of the RFP and omit "incremental hydroelectric generation" as a defined term; and (5) the hydroelectric generation will fail to provide required GHG emissions reductions.

b. <u>Eligible Clean Energy Generation</u>

NextEra argues that the PPAs contain a definition of "Hydro-Québec Power Resources"[42] that is inconsistent with the statutory definition of clean energy generation applicable to Section 83D. Specifically, NextEra asserts that use of the term "predominantly" when describing the resources that will provide the energy and associated environmental attributes under the PPAs, allows HQUS to deliver energy that is not produced by hydroelectric resources and, therefore, is inconsistent with the statutory definition of clean

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41 As discussed in n.36, above, the Department will address the issue of whether the hydroelectric generation complies with the statutory definition of firm service hydroelectric generation in Section VI.D, below.

42 The PPAs define "Hydro-Québec Power Resources" as "collectively, those existing hydroelectric generating stations, located in the Province of Québec and owned and operated as a system by Hydro-Québec or its subsidiaries from time to time, that produce electric energy, which consists predominantly of low-carbon and renewable hydro-electric energy during the Services Term, which are further described in Exhibit A" (Exhs. JU-3-A at 13; JU-3-B at 14; JU-3-C a 13).

energy generation that requires firm service hydroelectric generation from hydroelectric generation alone (NextEra Brief at 3, citing Section 83B).

The PPAs require HQUS to deliver qualified clean energy to the Companies, defined as "energy produced by a hydroelectric generating resource" (Exhs. JU-3-A at 16-17; JU-3-B at 18; JU-3-C at 16-17). The PPAs also provide that all deliveries of energy and associated environmental attributes must be produced by the Hydro-Québec Power Resources that are specified in Exhibit A (Exhs. JU-3-A at 29; JU-3-B at 31; JU-3-C at 29). Exhibit A identifies the 62 hydroelectric generating facilities operated by Hydro-Québec that comprise the Hydro-Québec Power Resources (Exhs. JU-3-A at Exhibit A; JU-3-B at Exhibit A; JU-3-C at Exhibit A). Accordingly, the Department finds that, under the PPAs, the Companies will purchase energy and environmental attributes deriving from the 62 hydroelectric generating facilities that comprise the Hydro-Québec Power Resources.

The PPAs describe the energy produced by the hydroelectric generating stations identified in Exhibit A as consisting "predominantly of low-carbon and renewable [hydroelectric] energy[43]" (Exhs. JU-3-A at 13; JU-3-B at 14; JU-3-C at 13). Although the Hydro-Québec Power Resources consist "predominantly" of resources producing low-carbon and renewable hydroelectric energy, the PPAs require that all energy from that resource mix that the Companies purchase pursuant to the PPAs is generated exclusively by hydroelectric resources (Exhs. JU-3-A at 16-17; JU-3-B at 18; JU-3-C at 16-17). Contrary to NextEra's

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43 Hydro Québec's sources of energy supply are 98 percent renewable resources (Exhs. EDC-NEER-1, at 2-3, Att.; EDC-NEER, Att. 3, at 1-2; EDC-RB-1, at 15).

assertion, the PPAs' inclusion of the term "predominantly" as part of the definition of "Hydro-Québec Power Resources" does not allow the Companies to purchase non-hydroelectric generation pursuant to the PPAs or to purchase hydroelectric generation that is not qualified clean energy. The PPAs are unambiguous that (1) the Companies must purchase qualified clean energy; (2) the qualified clean energy must be generated by hydroelectric resources; and (3) as discussed further below, the qualified clean (hydroelectric) energy must be tracked in the NEPOOL GIS[44] to ensure a unit-specific accounting of the delivery of qualified clean (hydroelectric) energy (Exhs. JU-3-A at 7, 16-17: JU-3-B at 7, 18; JU-3-C at 7, 16-17). Therefore, the Department finds that HQUS will deliver and the Companies will purchase qualified clean energy from hydroelectric generation alone (Exhs. JU-3-A at 7, 16-17; JU-3-B at 7, 18; JU-3-C at 7, 16-17). Accordingly, incorporating the findings in Section VI.D, below, regarding firm service hydroelectric generation, the Department finds that the hydroelectric generation in the PPAs complies with the statutory definition of clean energy generation in Section 83B applicable to Section 83D.

c. Clean-Energy Tracking System

A long-term contract procured pursuant to Section 83D(j) must use an appropriate tracking system to ensure a unit-specific accounting of the clean-energy delivery, to enable the Department of Environmental Protection ("DEP"), in consultation with DOER, to accurately measure progress in achieving the Commonwealth's goals under the GWSA or the

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44 The use of NEPOOL GIS as an appropriate tracking system under Section 83D(j) is addressed in Section VI.B.3.e, below.

Climate Protection and Green Economy Act, G.L. c. 21N. In this regard, the PPAs require that energy delivered by HQUS be tracked in the NEPOOL GIS to ensure a unit-specific accounting of those deliveries so that DEP can account for it in the state GHG emissions inventory created pursuant to the GWSA (Exhs. JU-3-A at 16-17; JU-3-B at 17-18; JU-3-C at 16-17). HQUS is responsible for showing that it is delivering energy and environmental attributes from qualified clean energy generation resources (Exh. EDC-RB-1, at 13). Further, the PPAs do not require the Companies to accept environmental attributes that are not associated with the specified MWh of generation from qualified clean energy generation (Exhs. EDC-RB-1, at 13-14; JU-3-A at § 4.1(b); JU-3-B at § 4.1(b); JU-3-C at § 4.1(b)).

NextEra and Acadia Center argue that the NEPOOL GIS tracking system is unable to verify that the energy delivered under the PPAs is hydroelectric energy and not system energy imported from Québec that includes energy originating from non-clean energy generation resources (NextEra Brief at 8; Acadia Center Reply Brief at 8-9). The NEPOOL GIS tracking system is a well-established power generation and associated environmental attribute tracking system used in the New England region.[45] The PPAs require HQUS to create, track, record, and transfer all environmental attributes associated with contract energy to the Companies, in compliance with all relevant NEPOOL GIS operating rules

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[45] NEPOOL GIS issues and tracks certificates for all MWh of generation and load produced in the ISO-NE control area, as well as imported MWh from adjacent control areas. In addition to the generation, the NEPOOL GIS provides emissions labeling for the New England load serving entities by tracking the emissions attributes for generators in the region. See https://www.nepoolgis.com/about/.

(Exhs. JU-3-A at 16-17, 34; JU-3-B at 18, 37; JU-3-C at 16-17, 34). These protections will ensure that the Companies purchase clean energy generation as defined by statute, and not system energy that contains non-clean energy generation (Exhs. JU-3-A at 16-17, 34; JU-3-B at 18, 37; JU-3-C at 16-17, 34). Accordingly, the Department finds that the PPAs use an appropriate tracking system, consistent with Section 83D(j).

d. Incremental Hydroelectric Generation

Certain intervenors argue that the PPAs do not satisfy the RFP's requirements regarding the procurement of incremental hydroelectric generation (see e.g., Attorney General Brief at 17-19; Acadia Center Reply Brief at 5; NextEra Brief at 11; NEPGA Brief at 7-10; RENEW Brief at 6; Sierra Club Brief at 7-9, 11; WMIG Reply Brief at 5). In particular, these intervenors maintain that the NECEC Hydro bid included contract energy that would be incremental as defined by the RFP, however, the executed PPAs do not require the procured energy to be incremental to historical average deliveries (Attorney General Brief at 17-19; Acadia Center Reply Brief at 5; NextEra Brief at 11; NEPGA Brief at 7-10; RENEW Brief at 6; Sierra Club Brief at 7-9, 11; WMIG Reply Brief at 5). To address this issue, the Attorney General argues that the Companies and HQUS should be required to renegotiate Exhibit H to the PPAs, in order to subject HQUS to penalties if it fails to deliver a minimum baseline amount of 14.80 TWh per year, in addition to the contract quantity of 9.55 TWh (Attorney General Brief at 17-26). NextEra, NEPGA, RENEW, and Sierra Club argue that because the PPAs do not comply with the RFP's definition of incremental hydroelectric generation, the evaluation of NECEC Hydro as the winning bid is in question

(NEPGA Brief at 7-9; NextEra Brief at 11-12; RENEW Brief at 5; Sierra Club Brief at 7-11). Conversely, DOER, the Companies, and HQUS maintain that Section 83D does not require the PPAs to guarantee delivery of a historical level of electricity into the region in addition to the delivery of 9.45 TWh of clean energy generation (see e.g., Companies Reply Brief at 7-8; DOER Reply Brief at 4-5; HQUS Reply Brief at 3-7). Nonetheless, these parties contend that the PPAs incorporate meaningful safeguards to ensure that the procured hydroelectric generation is incremental (Companies Reply Brief at 11-12; DOER Reply Brief at 4-5; HQUS Reply Brief at 7).

For the reasons discussed below, the Department finds that the PPAs will enable the Companies to procure, and HQUS to deliver, incremental hydroelectric power from Québec into ISO-NE that is fully consistent with definition of incremental included in the RFP (Exhs. AG-DM-Rebuttal-1, at 16-17; EDC-RB-1, at 18-19). Historically, and until NECEC becomes operational, HQUS has sold hydroelectric power into the ISO-NE control zone over existing transmission infrastructure primarily through non-firm commercial deliveries that fluctuate depending on market conditions and transmission constraints (Tr. 2, at 202-203). The new NECEC transmission line specifically enables HQUS to deliver firm hydroelectric generation from Québec into New England pursuant to a firm delivery schedule that is distinct from, and in addition to, its existing commercial trading activities (Exh. JU-1, at 36-38, 40; Tr. 2, at 204, 213).

The PPAs explicitly provide that the output of the Hydro-Québec Power Resources, delivered through NECEC, will be incremental hydroelectric generation (Exhs. JU-3-A at 7;

JU-3-B at 7; JU-3-C at 7). The PPAs do not, however, include the definition of incremental hydroelectric generation that was included in the RFP and form PPA (See Exhs. JU-3-A at 7-20; JU-3-B at 7-20; JU-3-C at 7-20). The Department finds that the omission of this definition does not call into question the selection of NECEC Hydro as the winning bid or otherwise invalidate the PPAs. Instead, as discussed below, the Department finds that the PPAs satisfy the RFP's requirement regarding the procurement of incremental hydroelectric generation and contain additional ratepayer protections to ensure that the hydroelectric generation being procured is incremental, which were not addressed in the RFP.

As discussed in Section V, above, the Companies issued the RFP consistent with the solicitation method approved by the Department in D.P.U. 17-32 (Exh. IE Report at 7). In addition, the Evaluation Team screened and evaluated bids consistent with the criteria described in the RFP, including the application of the definition of incremental hydroelectric generation[46] (Exh. IE Report at 48, 50-54). After NECEC Hydro was selected as the winning bid, the Companies and HQUS progressed to the contract negotiation stage (Exh. IE Report at 36). At that stage of the solicitation process, it was appropriate for the contracting parties to negotiate contract terms that could differ from the form PPA, so long

46 All bids were screened for threshold requirements in Stage One of the bid evaluation process (Exh. IE Report at 21). In Stage One, for example, the Evaluation Team eliminated one bid from an existing hydroelectric facility that it found did not supply incremental hydroelectric power (Exh. IE Report at 22). All projects that were evaluated in Stage Two met the requirement of incremental hydroelectric generation, where applicable, including the NECEC Hydro project (Exh. IE Report at 22-23, App. C; Tr. 2, at 202).

as the executed PPAs were consistent with Section 83D and designed to ensure that ratepayers would receive the full benefit of the bid.

As noted above, one such negotiated term was the omission of the definition of incremental hydroelectric generation that was included in the RFP and form PPA (however, as discussed above, regardless of the omission, the PPAs provide that HQUS will deliver incremental hydroelectric generation) (Exhs. JU-3-A at 7; JU-3-B at 7; JU-3-C at 7). An additional negotiated term was to add a company-specific Exhibit H to each PPA[47] (Exhs. JU-3-A at Exhibit H; JU-3-B at Exhibit H; JU-3-C at Exhibit H).

Contrary to intervenors claims, the RFP did not solely require the procured energy to be incremental to historical average deliveries. Instead, the RFP defined two ways to measure incremental; by applying the three-year historical average of annual hydroelectric deliveries or by applying a forward looking lens that considers "otherwise expected" levels of such deliveries. This two-pronged approach acknowledges that much of the hydroelectric generation HQUS delivers outside of the PPAs is marketed pursuant to non-firm transactions dictated by market conditions that are inherently variable and unpredictable (Exh. EDC-RB-1, at 23-24). By including the option that incremental hydroelectric generation could reflect an increase over "otherwise expected deliveries," the RFP acknowledged that a commitment to deliver a specific quantity of non-firm energy, as defined by a historical three-year period, over the duration of a 20-year contract, may present practical difficulties. Consistent with

[47] Exhibit H was not included in the form PPA.

the RFP, the PPAs provide for the procurement of firm hydroelectric energy in addition to the hydroelectric energy that HQUS would otherwise be expected to deliver to New England through its ongoing, largely non-firm commercial trading activities[48] (Exhs. JU-3-A at Exhibit B; JU-3-B at Exhibit B; JU-3-C at Exhibit B).

The Department finds that Exhibit H provides an incentive for HQUS to deliver the otherwise expected hydroelectric power to ISO-NE at certain levels and does not establish a baseline level of incremental hydroelectric generation, as suggested by the Attorney General and other intervenors (Exhs. IE Report at 22-23, 48, 51-53, App. C; JU-3-A at Exhibit H; JU-3-B at Exhibit H; JU-3-C at Exhibit H; Tr. 2, at 202, 207, 214). Exhibit H imposes penalties on HQUS for failing to deliver an annual quantity of baseline hydroelectric generation specified in Exhibit H to any delivery point in New England (Exhs. JU-3-A at Exhibit H; JU-3-B at Exhibit H; JU-3-C at Exhibit H). Exhibit H to the Eversource and Unitil PPAs are identical, and contain different terms from Exhibit H to the National Grid PPA (see Exhs. JU-3-A at Exhibit H; JU-3-B at Exhibit H; JU-3-C at Exhibit H). More specifically, Exhibit H for Unitil and Eversource requires a fixed amount of 3.00 TWh of baseline hydroelectric generation, while the National Grid Exhibit H's provides for 9.45 TWh, with potential downward adjustments based on an adjustment formula (Exhs. JU-3-A at Exhibit H; JU-3-B at Exhibit H; JU-3-C at Exhibit H; Tr. 2, at 198-200, 208-214).

48 The Companies anticipate HQUS's deliveries apart from the PPAs to continue in the range of between 9.45 TWh and 18.00 TWh annually (Tr. 2, at 204, 208).

Exhibit H addresses HQUS' sale of hydroelectric generation distinct and apart from its obligation to deliver firm hydroelectric generation under the PPAs (Exhs. JU-3-A at Exhibit H; JU-3-B at Exhibit H; JU-3-C at Exhibit H). The baseline hydroelectric generation to be supplied pursuant to Exhibit H is separate from, and additional to, the requirements for the delivery of firm hydroelectric generation as defined in the firm delivery schedules contained in the PPAs (Exhs. JU-3-A at Exhibit H; JU-3-B at Exhibit H; JU-3-C at Exhibit H). Conversely, we find that Exhibit H does not establish the expected delivery or cap of otherwise expected deliveries of hydroelectric generation during the contract term (Exh. IE Report at 22-23, 48, 51-53, App. C; Tr. 2, at 199, 202, 207-208).

For the reasons discussed above, the Department finds that the PPAs provide for the procurement of firm hydroelectric energy in addition to what HQUS would otherwise be expected to deliver to New England through its ongoing, largely non-firm commercial trading activities and that Exhibit H strengthens HQUS' commitment to deliver incremental hydroelectric generation on a firm basis for the 20-year term of the PPAs. Therefore, we find that the PPAs are consistent with the RFP's requirements regarding incremental hydroelectric generation and designed to ensure that ratepayers would receive the full benefit of the bid.

As a final matter, the Department recognizes that the PPAs are the result of separate negotiations between each individual electric distribution company and HQUS. As the priorities of the Companies are not identical, the resulting terms in each Exhibit H are not identical (Tr. 2, at 208-210). While these differences may have a legitimate basis, differences in the terms of Exhibit H could result in one company receiving more favorable treatment than others in circumstances where HQUS fails to deliver baseline hydroelectric generation at certain levels (Tr. 2, at 214-215). In future joint statewide long-term contract solicitations, the Department strongly encourages the Companies to minimize differences among them regarding material PPA terms. Timetable and Method of Second Solicitation of Long-Term Contracts for Offshore Wind Energy Generation Pursuant to Section 83C, D.P.U. 19-45, at 27-28 (May 17, 2019).

e. Greenhouse Gas Emission Reduction Benefits

The Companies' cost-benefit model showed that the NECEC Hydro bid will provide a projected GHG emissions reduction of 36.61 MMTCO2e for 2019 through 2040, relative to the Section 83D base case (Exhs. JU-1, at 44; JU-7, at 2). Sierra Club, NextEra, and NEPGA argue that the Companies have not shown that NECEC Hydro will provide GHG emissions reduction benefits to the Commonwealth because the Companies modeled the GHG benefits based on unreliable hydroelectric energy import figures (i.e., at levels reflecting 2012 load profile levels rather than the minimum baseline levels described in Exhibit H) (Sierra Club Brief at 13; NextEra Brief at 12; NEPGA Brief at 12).

The Companies will calculate actual GHG emissions reductions during each year of the contract term, based on the firm hydroelectric energy delivered pursuant to the PPAs and the hydroelectric energy delivered into New England outside of the PPAs (Tr. 2, at 217-219). The Department finds that the Companies' use of 2012 import data to model estimated GHG emissions reductions is a reasonable method to estimate benefits, both before contract implementation and before benefits are accrued (Tr. 1, at 48-50). Accordingly, The Department finds that the GHG emissions reduction benefits in the Companies' cost-benefit analysis are reliable estimates based on reasonable assumptions (Exh. JU-6, at 36-37; Tr. 2, at 217-218).

The realization of these benefits will depend primarily on hydroelectric power deliveries outside of the PPAs that will be affected by market conditions and transmission constraints in each year of the contract term. As discussed above, the Exhibit H baseline hydroelectric generation quantities do not represent expected deliveries into New England, but rather a level of deliveries below which penalties will be assessed to HQUS (Exhs. JU-3-A at Exhibit H; JU-3-B at Exhibit H; JU-3-C at Exhibit H). Although market conditions may cause HQUS's commercial delivery of hydroelectric power into New England outside of the PPAs to change from year to year and, therefore, affect the overall GHG emissions levels in the Commonwealth, the Department finds that the firm hydroelectric power delivered under the PPAs will create steady GHG emissions reduction benefits to Massachusetts.

f. Conclusion

The Department found above that the hydroelectric generation in the PPAs complies with the statutory definition of clean energy generation in Section 83B applicable to Section 83D. As we find in Section VI.D, below, the hydroelectric generation in the PPAs also complies with the statutory definition of firm service hydroelectric generation in Section 83D(j). Further, the Department found above that, consistent with Section 83D(j), the long-term contracts use an appropriate tracking system to ensure a unit specific accounting of the delivery of clean energy and provide the required GHG emissions reductions. Finally, the Department found above that the PPAs will ensure the delivery of incremental hydroelectric generation, consistent with the RFP, and the energy delivered under the PPAs will create steady GHG emissions reduction benefits to Massachusetts. Accordingly, the Department finds that the hydroelectric generation from NECEC Hydro is an eligible clean energy generation resource under Section 83D.

C. Facilitation of Financing

1. Introduction

Section 83D requires the Companies to conduct one or more competitive solicitations for clean energy generation resources and, provided that reasonable proposals have been received, to enter into long-term contracts for such resources. Section 83D(a); 220 CMR 24.01(1), 24.03. To approve the contracts, the Department must find that the long-term contracts will facilitate the financing of the clean energy generation resources. Section 83D(a); See D.P.U. 13-146 through D.P.U. 13-149, at 31; D.P.U. 11-05 through D.P.U. 11-07, at 14-15.

2. Positions of the Parties

a. New England Power Generators Association

NEPGA argues that, because the PPAs would allow most of the contract deliveries to substitute for historical deliveries, the PPAs would allow Hydro-Québec to provide less clean energy to New England than it has historically (NEPGA Brief at 11; NEPGA Reply Brief at 10). NEGPGA concludes this would not facilitate the financing of clean energy generation as required by Section 83D (NEPGA Brief at 7 & n.9, 11; NEPGA Reply Brief at 10).

b. Companies

The Companies maintain that the FERC-approved TSAs will help CMP obtain financing for NECEC (Companies Brief at 21, citing Exhs. JU-1, at 44, WP Support Tab B). More specifically, the Companies argue that, without the financial strength they provide as credit-worthy contract counterparties, it is highly unlikely that NECEC would be financeable at all (Companies Brief at 21, citing Exhs. EDC-RBH-GET-1, at 63, 65-66; DPU 2-11; DPU 3-7). No other party addressed this issue on brief.

3. Analysis and Findings

Section 83D requires an electric distribution company to demonstrate that any proposed long-term contract will facilitate the financing of the clean energy generation resource. To satisfy this requirement, an electric distribution company need not demonstrate that the long-term contract is necessary to secure project financing, only that it will assist in securing project financing. NSTAR Electric Company, D.P.U. 12-30, at 40 (2012); Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 10-54, at 52-53 (2010).

While the energy associated with the NECEC Hydro bid will be generated by a combination of 62 operational hydroelectric generating facilities, the clean energy generation will be delivered into New England over a new NECEC transmission lines. The Department has found that a long-term contract with a creditworthy counterparty, such as an electric distribution company, allows a developer to obtain favorable long-term financing. D.P.U. 17-117 through D.P.U. 17-120, at 30; D.P.U. 13-146 through D.P.U. 13-149, at 32; D.P.U. 11-05 through D.P.U. 11-07, at 18-19.

NEPGA argues that the PPAs will allow Hydro-Québec to provide less clean energy to New England than it has historically and, therefore, will not facilitate the financing of clean energy generation. In Section VI.B, above, the Department found that NECEC Hydro will deliver incremental hydroelectric generation in and, therefore, NEPGA's contention is without basis. After review, the Department finds that, consistent with Section 83D(a), the Companies have demonstrated that the long-term contracts will facilitate CMP's ability to finance NECEC (Exhs. EDC-RBH-GET-1, at 63, 65-66; DPU 2-11; DPU 3-7; JU-1, at 44).

D. Reduced Winter Electricity Price Spikes and Guaranteed Delivery in Winter Months

1. Introduction

Pursuant to Section 83D, the Department must determine that that the clean energy generation resource (1) contributes to reducing winter electricity price spikes and (2) guarantees energy delivery in winter months. Section 83D(d)(5)(ii), (vi); 220 CMR 24.24.05(2), (6). To address these requirements, the RFP required bidders to (1) demonstrate that the project will contribute to a reduction in winter electricity price spikes by guaranteeing delivery during peak winter months as well as when a cold weather event is called by ISO-NE; and (2) guarantee clean energy delivery in the winter months (Exh. JU-2, at §§ 2.2.2.5, 2.2.2.7).

2. Positions of the Parties

a. NextEra Energy Resources

NextEra argues that the PPAs do not qualify as firm hydroelectric generation under Section 83D because they (1) allow HQUS not to deliver hydroelectric generation up to 20 percent of the time (i.e., 73 days a year) without triggering a contract default and (2) do not designate any periods during which delivery curtailment is prohibited (NextEra Brief at 6, citing Exh. JU-3-B at 56). NextEra also argues that the PPAs cannot ensure firm service because the hydroelectric generating plants owned by HQUS have preceding supply obligations (NextEra Brief at 7).

In addition, NextEra asserts that because HQUS may interrupt delivery and pay cover damages at any time of year, the PPAs fail to meet the statutory requirements that the clean energy generation resource guarantee winter delivery and reduce winter price spikes (NextEra Brief at 19). As support for these assertions, NextEra claims that Hydro-Québec historically has elected not to sell energy into ISO-NE grid during the winter (NextEra Brief at 19, citing Exh. RSW-S-1, at 17). NextEra also argues that, while the cover damages provision will make ratepayers whole financially with respect to projected direct energy benefits, the cover damages provision fails to account for the loss of non-delivery related indirect benefits, which it maintains are approximately ten times the magnitude of the direct benefits (NextEra Brief at 19-20, citing Tr. 2, at 367-368; Exh. RSW-S-1, at Figs. RSW-1, RSW-2).

b. New England Power Generators Association

NEPGA argues that because the PPAs allow HQUS to cure a delivery default at any time during any corresponding season in the current or subsequent contract year, there is no basis for the Department to conclude that the PPAs will guarantee energy delivery in the winter months as required by Section 83D (NEPGA Brief at 10; NEPGA Reply Brief at 7). In this regard, NEPGA asserts that a delivery cannot be considered firm if the seller is excused from performance today as long as it provides replacement power at some time in the next year (NEPGA Reply Brief at 7-8).

In addition, NEPGA maintains that Section 83D does not allow the Companies to procure an "insurance policy" in the form of the cover damages provision of the PPAs, in lieu of firm deliveries in the winter months (NEPGA Reply Brief at 8). Finally, NEPGA argues that a lack of firm winter deliveries undermines the basis for the Department to conclude that the PPAs will reduce winter price spikes (NEPGA Initial Brief at 10; NEPGA Reply Brief at 8).

c. The Energy Consortium

TEC argues that the way HQUS is able to cure winter delivery shortfalls under the PPAs is inconsistent with the requirements of Section 83D (TEC Reply Brief at 5, citing Exh. JU-3-A at § 4.3(c)(vi); JU-3-B at § 4.3(c)(vi); JU-3-C at § 4.3(c)(vi)). In addition, TEC argues that there is evidence that Hydro-Québec or its affiliates have reduced deliveries to New England during some cold weather events (TEC Reply Brief at 6). TEC urges the Department to amend the PPAs to strengthen HQUS' delivery obligations during the peak winter period and, specifically, to require HQUS to provide firm service during any period where ISO-NE has declared a capacity scarcity condition (TEC Reply Brief at 6).

d. Central Maine Power Company

CMP argues that the PPAs and TSAs satisfy both the statutory and RFP requirements to guarantee energy delivery in the winter months (CMP Brief at 6). CMP contends that these firm winter energy deliveries will reduce the amount of natural gas generation needed to serve load during natural gas supply constraints, thereby serving as a hedge to mitigate winter electricity price spikes (CMP Brief at 6).

e. H.Q. Energy Services (U.S.)

HQUS argues that the PPAs will contribute to reducing winter electricity price spikes because they provide for the firm delivery of 9,554,940 MWh of clean energy generation to be offered into the ISO-NE spot market, which will act as a hedge against high winter energy prices when there are natural gas supply constraints (HQUS Brief at 10, citing Exh. JU-1, at 40). Moreover, HQUS contends that under the cover damages provision of the PPAs, HQUS bears the market risk of winter energy price spikes, not the Companies and their customers (HQUS Brief at 11, citing Exh EDC-RB-1, at 52).

In addition, HQUS argues that the PPAs will guarantee delivery in winter months because they include a schedule of guaranteed qualified clean energy deliveries, including guaranteed deliveries during the winter months (HQUS Brief at 11, citing Exhs. JU-1, at 42; JU-3-A at Exhibit. B; JU-3-B at Exhibit B; JU-3-C at Exhibit B). HQUS maintains that the PPAs provide that HQUS "shall not sell, divert, grant, transfer or assign" the products to any entity other than buyer (HQUS Brief at 11, citing Exh. EDC-RB-1, at 36). HQUS also maintains that although the PPAs permit HQUS to cure a delivery shortfall that occurs during a winter period with physical energy flows of qualified shortfall energy, it may do so only within the winter period and during the same corresponding on-peak or off-peak hours (HQUS Brief at 11, citing Exh. EDC-RB-1, at 34).

HQUS maintains that, over the last 20 years, there have been no instances where Hydro-Québec or its affiliates failed to fulfill their firm delivery export obligations due to an energy production shortage during the months of December, January, or February (HQUS Brief at 11, citing Exh. DPU 2-9). Finally, HQUS contends that the Companies have demonstrated, based on historical prices, there is no substantial likelihood of a market opportunity arising that would be sufficient for HQUS to arbitrage the PPA cover damages (HQUS Brief at 11, citing Exh. EDC-RB-1, at 35-36).

f. Companies

The Companies dispute NEPGA's and NextEra's contention that the PPAs fail to guarantee winter delivery and reduce winter price spikes (Companies Reply Brief at 17). The Companies assert that the PPAs must be interpreted based on the intent of the contracting parties at the time the agreements were entered into and the circumstances surrounding the making of the agreements must be examined to determine the objective intent of the parties (Companies Reply Brief at 17). In this regard, the Companies argue that the PPAs are the result of a solicitation for clean energy generation that includes hydroelectric generation provided on a firm basis where bidders were specifically put on notice that they must guarantee delivery during peak winter months as well as when a cold weather event is called by ISO-NE (Companies Brief at 27 citing Exhs. JU-1, at 36, 42; JU-3-A at Exhibit B; JU-3-B at Exhibit B; JU-3-C at Exhibit B; Companies Reply Brief at 17-18). The Companies contend that the PPAs are consistent with the intent to guarantee winter delivery and reduce winter price spikes as demonstrated by HQUS' obligation under the PPAs to deliver energy in accordance with a schedule which is firm and not subject to interruption except by force majeure (Companies Reply Brief at 18 citing JU-3-A at 29; JU-3-B at 31; JU-3-C at 29).

The Companies further argue that NextEra's interpretation of the cover damages provision runs counter to the intent of the contracting parties (Companies Reply Brief at 19, citing Exh. NEER-RSW-1 at 16). In particular, the Companies argue that NextEra's claim that the cover damages provision transforms the PPAs from a firm sale to a "put option" incorrectly assumes that HQUS would be willing to ignore its obligations under the PPAs and risk disrupting its long-term relationship with the Companies in order pursue short-term arbitrage profits (Companies Reply Brief at 19). The Companies assert that they have analyzed the potential for HQUS to arbitrage contract energy and, based on historical data, profitable arbitrage opportunities exist in only 0.2 percent of hours (Companies Reply Brief at 20, citing Exh. EDC-RB-1 at 35). The Companies maintain that there is no evidence that HQUS will intentionally fail to meet its guaranteed delivery obligations to divert contract energy to more profitable markets (Companies Reply Brief at 19). The Companies further argue that NextEra's assertion that HQUS has chosen not to deliver to ISO-NE in the winter is not supported by evidence, and the cited instances where HQUS reduced energy imports into New England were the result of idiosyncratic factors rather than economic ones (Companies Reply Brief at 22).

In addition, the Companies maintain that the PPAs include significant protections for Massachusetts ratepayers in the event of non-deliveries, including during ISO-NE winter price spike conditions (Companies Brief at 25; Companies Reply Brief at 22). The Companies assert that the cover damages provision ensures that customers will not pay more for energy deliveries than they would have under the contract in the event of an uncured delivery shortfall (Companies Reply Brief at 22-23). The Companies further argue that shortfall-cure amounts delivered in the event of a non-excused outage on NECEC or the Québec Line, enhance contract firmness by requiring that any shortfall-cure energy be delivered in the corresponding period where there was an energy non-delivery (Companies Reply Brief at 23, citing Exh. EDC-RB-1, at 34-35).

Finally, the Companies argue that NextEra incorrectly interprets the requirement in Section 83D(d)(ii) that the clean energy resources "contribute to reducing winter electricity price spikes" to require the PPAs to absolutely eliminate any fiscal impact of energy non-delivery (Companies Reply Brief at 24-25). Instead, the Companies assert that the plain meaning of the statute does not require a single long-term contract to eliminate winter electricity price spikes entirely (Companies Reply Brief at 24-25). The Companies conclude that any such requirement would contradict established statutory precedent, increase contract costs for customers, and increase contract risks for developers (Companies Reply Brief at 25-26).

3. Analysis and Findings

a. Introduction

Section 83D(d)(5)(ii) requires the Department to find that the clean energy resources in the PPAs "contribute to reducing winter electricity price spikes." In addition, pursuant to Section 83D(d)(5)(vi), the clean energy generating resources must "guarantee energy delivery in winter months."

NextEra, NEPGA, and TEC argue that the PPAs contain provisions that allow HQUS to elect not to deliver energy under certain circumstances, and these provisions render NECEC Hydro ineligible as clean energy generation resource under Section 83D because they are inconsistent with Section 83D's requirements that clean energy resources must contribute to reducing winter electricity price spikes and guarantee energy delivery in winter months[49] (see e.g., NextEra Brief at 19; NEPGA Brief at 10; TEC Reply Brief at 6). The Companies, HQUS, and CMP maintain, however, that NECEC Hydro will provide eligible firm service hydroelectric generation that will both contribute to reducing winter electricity price spikes and guarantee energy delivery in the winter months (see e.g., Companies Reply Brief at 17-19; HQUS Brief at 11; CMP Brief at 6).

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49 Additional arguments regarding these provisions as they relate to more broadly to NECEC Hydro's eligibility as Section 83D clean energy generating resource are also addressed in this section. See Section VI.B, above.

b. Reducing Winter Price Spikes

When determining whether a resource will contribute to reducing winter electricity price spikes, the Department considers a project's output and capacity factor at the electric system's peak, and we have found that a generating resource contributes to reducing winter electricity price spikes if it produces power during peak winter conditions. D.P.U. 18-76 through D.P.U. 18-78, at 32-33, citing D.P.U. 17-117 through D.P.U. 17-120, at 33 & D.P.U. 10-54, at 198.

NECEC Hydro provides for 9.55 TWh of firm, qualified clean energy generation pursuant to a schedule of guaranteed deliveries on a monthly basis (including winter months), for each year of the contract term (Exhs. JU-3-A at Exhibit B; JU-3-B at Exhibit B; JU-3-C at Exhibit B; JU-1, at 40). The generation will be offered into ISO-NE's spot market without a price reserve (Exh. JU-1, at 40). This allows the generation to be a hedge during times of winter natural gas supply constraints and reduce the amount of natural gas-fired generation required to meet electricity demand[50] (Exh. JU-1, at 40; Tr. 2, at 268). Accordingly, pursuant to Section 83D and 220 CMR 24.05(1)(a)(2), the Department finds

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50 Constraints on natural gas supply cause winter electricity price spikes because firm heating customers retain priority access to limited regional pipeline delivery capacity and may fully utilize their capacity during cold snap conditions. Many electricity generators have lower priority non-firm delivery arrangements and are unable to access gas supply and/or are forced to arrange higher cost alternative fuel supplies during those same peak demand conditions. In response, the region experiences short-duration spikes in wholesale electricity prices.

that the NECEC Hydro will contribute to the reduction of winter electricity price spikes. D.P.U. 18-76 through D.P.U. 18-78, at 33.

c. Guaranteed Delivery in Winter Months

Section 83D is the first instance where the Department must consider whether a clean energy generating resource subject to a long-term contract guarantees delivery in the winter months. See Section 83D(c)(5)(vi); 220 CMR 24.05(6). Section 83D does not define "winter months;" however, the Department finds that the PPA's definition of "winter period" as December, January, and February is a reasonable interpretation of "winter months" for the purpose of Section 83D (Exhs. JU-3-A at 20; JU-3-B at 23; JU-3-C at 20). Section 83D also does not impose any minimum requirements on the quantity or frequency of a generating resource's ability to deliver energy during the winter months. However, as noted above, each PPA includes a schedule of guaranteed qualified clean energy to be delivered from HQUS on a monthly basis for each year of the contract term (Exhs. JU-3-A at Exhibit B; JU-3-B at Exhibit B; JU-3-C at Exhibit B). As explained below, these obligations in the PPAs satisfy Section 83D's requirements regarding the quantity and frequency that a generating resource must guarantee delivery of energy during the winter months.

NEPGA and TEC argue that the PPAs allow HQUS to cure delivery shortfalls any time during the corresponding season in the current or subsequent contract year, and they claim that this allowance means that the PPAs do not guarantee energy delivery in winter months (NEPGA Brief at 10; NEPGA Reply Brief at 7; TEC Reply Brief at 5-6). In addition, NextEra and NEPGA argue that the PPAs allow HQUS to curtail delivery and sell the energy in other markets (up to 20 percent of hours annually) and this allowance undermines the firmness of winter energy deliveries (NextEra Brief at 6, 19-20; NEPGA Brief at 9-10; NEPGA Reply Brief at 7-8).

With regard to the argument that the PPAs do not guarantee winter delivery because they allow HQUS to cure delivery shortfalls, the Department finds that NEPGA and TEC incorrectly characterize the PPAs. The PPAs provide that HQUS may deliver qualified shortfall energy[51] in the event of a curable delivery shortfall (Exh. JU-3-A at § 4.3(c)(vi); JU-3-B at § 4.3(c)(vi); JU-3-C at § 4.3(c)(vi)). In the PPAs, "curable delivery shortfall" is a defined term describing delivery shortfalls caused by the following circumstances: (1) a non-excused outage of NECEC under the TSA;[52] and/or (2) an outage or reduction in the availability of the Québec Line due to a physical condition that affects the transfer capability of the Québec Line (Exhs. JU-3-A at 31; JU-3-B at 33; JU-3-C at 31; JU-4-A at 15; JU-4-B at 15; JU-4-C at 15). In each circumstance, the transmission line outages leading to the curable delivery shortfall are not related to any voluntary actions or otherwise in the control of HQUS. Rather, curable delivery shortfalls occur either during an outage on NECEC or

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[51] Qualified shortfall energy is energy produced by a hydroelectric generating resource and delivered over any transmission line by HQUS to the Companies into the New England control area during the term of the PPAs (Exh. JU-3-A at 17).

[52] A non-excused outage is any outage of NECEC or reduction in the total transfer capability below NECEC capacity, except due to an excused outage (Exh. JU-4-A at 15). Excused outages include events of force majeure, scheduled maintenance, outages in the Québec Line, and regulatory decisions affecting the operability of NECEC (Exh. JU-4-A at 36; JU-4-B at 36; JU-4-C at 36).

an outage caused by a physical condition on the Québec Line. Neither circumstance describes a situation where HQUS can elect not to deliver energy in the winter months (or otherwise), as suggested by NEPGA.

When a curable delivery shortfall situation arises, the PPAs limit the delivery of qualified shortfall energy to the same season-peak period as when the curable delivery shortfall occurred, in the same year or the immediately succeeding contract year (Exhs. JU-3-A at 31-32; JU-3-B at 33-34; JU-3-C at 31-32; JU-4-A at 15; JU-4-B at 15; JU-4-C at 15). In addition, the PPAs provide for an annual reconciliation of the difference between the weighted average LMP value for each curable delivery shortfall and the weighted average LMP value of the curable shortfall energy deliveries (Exhs. JU-3-A at 32-33; JU-3-B at 35; JU-3-C at 32-33).

Given the nature of electricity transmission, delivery shortfalls will occasionally happen. In addition, any long-term contract for renewable energy generation requires reasonable provisions to address them. As noted above, curable delivery shortfalls as defined in the PPAs are caused by circumstances that are outside of HQUS's control. By imposing limits on HQUS's ability to deliver curable shortfall energy and by providing a mechanism to ensure that ratepayers are made whole financially with respect to these deliveries, the Department finds that the PPAs' curable delivery shortfall provision is appropriate to allow HQUS to fulfill its firm delivery obligations while reasonably accommodating transmission outages that are not within its direct control.

With regard to NEPGA's and NextEra's arguments that HQUS can elect to not deliver whenever they have an opportunity to earn higher profits in other markets, the Department finds that the PPAs contain provisions that guarantee energy delivery on a year-round basis, including in winter months.[53] In particular, the PPAs require HQUS to provide energy and environmental attributes on a firm basis, consistent with the delivery schedule set forth in Exhibit B of the PPAs[54] (Exh. JU-3-A at 28-29, 72). This delivery requirement is firm and not subject to interruption except in three prescribed conditions: (1) force majeure;[55] (2) deliveries excused during negative LMP periods;[56] or (3) curable

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53 With respect to analyses offered by NextEra, NEPGA, and the Companies that rely on historical market data to attempt to assess the potential for HQUS to curtail firm deliveries during the contract term (particularly during the winter months), the Department finds that these analyses are highly speculative and, therefore, we do not rely on them in our determination whether the PPAs are consistent with Section 83D.

54 With regard to HQUS' obligation to sell its output on a constant, year-round basis, the PPAs provide that HQUS (1) "shall not sell, divert, grant transfer or assign" the energy and environmental attributes to any person other than the Companies during the contract term, and (2) "shall not claim or enter into any agreement or arrangement under which [the energy and environmental attributes] can be claimed" by any person other than the Companies (Exhs.JU-3-A at 29; JU-3-B at 31; JU-3-C at 29).

55 Force majeure applies to an event that (1) was not within the control of the party claiming its occurrence, (2) could not have been prevented or avoided by that party through the exercise of reasonable diligence, and (3) directly prohibits or prevents that party from performing its obligations under PPAs (Exh. JU-3-A at 53).

56 Section 4.2(a) of the PPAs provides a limited exemption that excuses deliveries during negative LMP periods (Exhs. JU-3-A at 29-30; JU-3-B at 31; JU-3-C at 29-30). Negative LMP periods occur when an energy system's supply exceeds demand. Consequently, delivery during those periods could result in wasted resources.

delivery shortfalls[57] (Exhs. JU-3-A at 29; JU-3-B at 31; JU-3-C at 29). An uncured delivery shortfall occurs if HQUS fails to deliver its products in situations where non-delivery is not excused by one of the three circumstances described above and HQUS has not cured the shortfall by delivering qualified shortfall energy (Exhs. JU-3-A at 31; JU-3-B at 33; JU-3-C at 31).

In the event HQUS fails to cure an unexcused delivery failure under the PPAs, it must pay cover damages for any shortfall[58] (Exhs. JU-3-A at 9, 31; JU-3-B at 33; JU-3-C at 31; EDC-RB-1, at 31). Cover damages are inclusive of all penalties and additional costs that the Companies may incur to purchase replacement energy in the event of non-deliveries (Exhs. JU-3-A at 9-10; JU-3-B at 10; JU-3-C at 9-10). Therefore, the Department finds that cover damages for uncured deliveries reasonably support the PPAs' firm energy delivery provision by (1) providing an appropriate incentive for HQUS to deliver energy during the winter months (and otherwise) and (2) making ratepayers financially whole in the event that an uncured delivery shortfall should occur.[59]

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[57] Curable delivery shortfalls are addressed under Section 4.3(c) of the PPAs.

[58] Cover damages are equal to the incremental costs that the Companies incur to replace and deliver energy and environmental attributes for any shortfall (Exhs. JU-3-A at 9-10; JU-3-B at 10; JU-3-C at 9-10).

[59] NextEra argues that cover damages do not include lost price suppression benefits (see NextEra Brief a 12-13). As discussed above, the payment of cover damages is one provision in the PPAs that is designed to provide an appropriate incentive for HQUS to deliver energy on a year-round basis, including in winter months. The payment of cover damages is only triggered in the event that HQUS fails to cure an unexcused delivery failure. The calculation of lost price suppression benefits related to an unexcused delivery failure would be highly speculative and we find that any mandate

NextEra incorrectly characterizes the cover damages provision of PPAs as a "put option" that allows HQUS to elect not deliver at will and divert those sales to a more profitable market (see Next Era Brief a 19-20). This argument relies on the faulty assumption that the only disadvantage for HQUS in failing to deliver during the winter months (or otherwise) under the PPAs is the payment of cover damages. As the Companies correctly note, if HQUS ignores its contractual obligations under the PPAs in pursuit of arbitrage positions, it will also harm its relationship with its customers and its reputation generally (see Companies Reply Brief at 19).[60]

For the reasons discussed above, the Department finds that NECEC Hydro will guarantee delivery in the winter months as required by Section 83D. See Section 83D(c)(5)(vi); 220 CMR 24.05(6). For these same reasons, the Department finds that NECEC Hydro meets the definition of firm service hydroelectric generation under Section 83D. Section 83B; 220 CMR 24.02.

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to include such amounts in cover damages would increase contract risk for project developers and likely increase contract costs for ratepayers. Therefore, the Department finds that it would not be appropriate to require the inclusion of lost price suppression benefits in cover damages.

60 The Department does not accept NextEra's argument that HQUS has preceding supply obligations that will prevent it from ensuring firm hydroelectric delivery to the Companies (see NextEra Brief at 7). Here, HQUS has contracted to supply firm service hydroelectric generation to the Companies and it must do so regardless of HQUS' other contractual arrangements.

E. Enhanced Electricity Reliability within Massachusetts

1. Introduction

Pursuant to Section 83D(d)(5)(i) and 220 CMR 24.05(1)(a)(1), the Department must find that the clean energy generating resource will "provide enhanced electricity reliability within the Commonwealth." While Section 83D does not define the term "reliability," the Department has previously relied on the Northeast Power Coordinating Council/North American Electric Reliability Council definition of reliability and defined "reliability" as the ability to contribute to system resource adequacy and system security. D.P.U. 18-76 through D.P.U. 18-78, at 29; D.P.U. 17-117 through D.P.U. 17-120, at 32; D.P.U. 13-146 through D.P.U. 13-149, at 34; D.P.U. 11-05 through D.P.U. 11-07, at 21; D.P.U. 10-54, at 181.

The RFP required bidders to commit any qualifying capacity to ISO-NE exclusively or provide other demonstrations that the proposed project provides enhanced electricity reliability within Massachusetts (Exh. JU-2, at 30). The RFP also required eligible resources to interconnect to the ISO-NE pool transmission facilities under the Capacity Capability Interconnection Standard[61] (Exh. JU-2, at 18).

[61] The Capacity Capability Interconnection Standard includes the criteria required to permit an interconnection customer to interconnect a generating facility in a manner that avoids any significant adverse effect on the reliability, stability, and operability of the New England transmission system, including protecting against the degradation of transfer capability for interfaces affected by the generating facility, and in a manner that ensures intra-zonal deliverability by avoidance of the re-dispatch of other capacity network (ISO—NE Transmission, Markets and Services Tariff Section II, Schedule 22, at Section I).

2. Positions of the Parties

a. NextEra Energy Resources

NextEra argues the NECEC Hydro bid will not provide enhanced reliability within Massachusetts because (1) the Larrabee Road substation[62] delivery point is located in a part of Maine that ISO-NE characterizes as having weak transmission infrastructure and (2) NECEC fails to alleviate constraints at two transmission interfaces that limit delivery of energy from Maine into Massachusetts (NextEra Brief at 13-16). NextEra asserts that because CMP will upgrade only the Surowiec-South interface, NECEC will not change the historical pattern of congestion on the Maine-New Hampshire and North-South interfaces and, therefore, energy from NECEC will not flow into the Commonwealth during peak periods (NextEra Brief at 16). Further, NextEra maintains that the Companies' modeling analysis does not support the proposition that there is a lack of congestion on the Maine-New Hampshire and North-South interfaces because the analysis incorrectly assumes that HQUS will provide fully incremental energy and does not account for the delivery flexibility allowed under the PPAs (NextEra Brief at 15). NextEra argues that this flawed reliance on a lack of congestion on the Maine-New Hampshire and North-South interfaces resulted in the selection of NECEC Hydro as the winning bid, even though the project will not enhance reliability within Massachusetts (NextEra Brief at 18). Finally, NextEra argues that, in order for

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62 The Larrabee Road substation is the southern terminus of NECEC and is located in Lewiston, Maine (Exhs. JU-4-A at 10; JU-4-B at 10; JU-4-C at 10).

NECEC Hydro to provide enhanced electricity reliability within the Commonwealth, significant additional transmission upgrades will be required[63] (NextEra Brief at 17).

b. New England Power Generators Association

NEPGA argues that NECEC Hydro will not provide enhanced reliability within Massachusetts because transmission congestion will prevent the energy from being fully deliverable into Massachusetts (NEPGA Reply Brief at 7-8, 12). NEPGA asserts that additional transmission upgrades will be needed to ensure that the clean energy generation under the PPAs is fully deliverable to Massachusetts (NEPGA Reply Brief at 13).

c. Department of Energy Resources

DOER argues that NECEC Hydro will provide enhanced reliability within the Commonwealth by increasing the transfer capability of firm hydroelectric generation into the regional grid and allowing increased power flows to Massachusetts (DOER Brief at 7-8). DOER further argues that NECEC Hydro will provide enhanced reliability within Massachusetts because it will deliver hydroelectric generation during cold temperature periods when New England faces constrained natural gas availability (DOER Brief at 7).

a. Central Maine Power Company

CMP argues that NECEC Hydro will provide enhanced reliability within Massachusetts because NECEC will include transmission upgrades that will increase transfer capability at the Surowiec-South interface from 1,600 MW to 2,600 MW and allow for firm

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63 NextEra's arguments regarding transmission upgrade costs are addressed in Sections VI.E.3, VI.F.3, and VII.C.

delivery to Massachusetts during normal system operations as well as unscheduled system outage events (CMP Brief at 5). CMP argues that, contrary to NextEra's claims, the Larrabee Road substation delivery point is not in a part of Maine that ISO-NE characterizes as having weak transmission infrastructure (CMP Reply Brief at 5). In fact, CMP argues that NextEra submitted a joint bid with CMP in the instant solicitation with the Larrabee Road substation as the project delivery point (CMP Reply Brief at 5-6).

In addition, CMP disputes NextEra's claim that the Maine-New-Hampshire and North-South interfaces are constrained such that the energy from NECEC Hydro will not flow to Massachusetts (CMP Reply Brief at 5). While CMP agrees that ISO-NE has identified a potential for the Maine capacity zone to become export-constrained for the purpose of the ISO-NE forward capacity market, CMP maintains that this does not establish that ISO-NE expects congestion at the Maine-New Hampshire or North-South Interfaces that would prevent NECEC Hydro energy deliveries from flowing to Massachusetts (CMP Reply Brief at 6). To the contrary, CMP argues that the Companies' production cost modeling demonstrates that NECEC Hydro will not experience significant congestion at these interfaces (CMP Reply Brief at 6).

Finally, CMP asserts that NextEra offered no modeling or other quantitative analysis to support its claims regarding energy congestion at the Maine-New Hampshire and North-South interfaces (CMP Reply Brief at 7-8). CMP maintains that, even if HQUS elects not to deliver energy during certain hours where permitted under delivery flexibility provisions in the PPAs, such non-deliveries could not create or exacerbate congestion at the

Maine-New Hampshire and North-South interfaces because, by definition, HQUS would inject no energy at the Larrabee Road substation during such hours (CMP Reply Brief at 7).

b. Companies

The Companies argue that NECEC Hydro will provide enhanced reliability within Massachusetts (Companies Brief at 22-24). The Companies assert that the NECEC Hydro bid satisfied the reliability requirement of the RFP through an exclusive commitment of any qualifying capacity to ISO-NE (Companies Brief at 22, citing Exhs. EDC-RB-1, at 38; EDC-RB-4, at 43). In addition, the Companies argue that NECEC Hydro will interconnect under the Capacity Capability Interconnection Standard, which obligates CMP to construct significant upgrades to the existing bulk electric system in New England (Companies Brief at 22; Companies Reply Brief at 32). The Companies maintain that these transmission system upgrades will increase the amount of power that can flow on a critical interface in Maine, which will allow for the delivery of firm, qualified clean energy generation to Massachusetts during normal system operations as well as various unscheduled system outage events (Companies Brief at 22-23).

The Companies assert that their dispatch model and related analysis support a finding that NECEC Hydro will enhance the delivery of power to Massachusetts (Companies Reply Brief at 32). The Companies maintain that, using conservative assumptions and modeling all known ISO-NE system constraints, the analysis shows reduced LMPs in Massachusetts with NECEC in operation (Companies Brief at 23; Companies Reply Brief at 32). Further, the Companies argue that NECEC will enable a more diverse fuel mix in the Commonwealth and maintain that the Department has found that enhancing fuel diversity in the region increases reliability (Companies Brief at 24, citing Exh. EDC-RB-1, at 38; D.P.U. 17-117 through D.P.U. 17-120, at 33.

The Companies also dispute NextEra's claims that NECEC fails to alleviate constraints at two transmission interfaces that limit the delivery of energy from Maine into Massachusetts (Companies Reply Brief at 22-23). With regard to NextEra's argument that NECEC Hydro will cause congestion on the Maine-New Hampshire and North-South transmission interfaces, the Companies assert that NextEra incorrectly relied an ISO-NE presentation that does not take into consideration the system upgrades CMP will complete in connection with NECEC and does not model the effects of NECEC (Companies Reply Brief at 33-34, citing Exhs. RSW-6; EDC-NEER 1-13, Att. 1). In addition, the Companies note that NextEra did not offer any independent modeling of constraints at the Maine-New Hampshire or North-South interfaces (Companies Reply Brief at 34). Finally, the Companies argue that NextEra's own bids in the instant solicitation would have injected energy at the same delivery point, and with roughly the same upgrades to the Surowiec-South interface, as the NECEC Hydro proposal (Companies Reply Brief at 36). The Companies maintain that, in connection with its own bids, NextEra stated that the "transmission project is tailored . . . to alleviate any transmission constraints from the area, allowing the full generating capacity . . . to reach [the ISO-NE pool transmission facilities] and benefit the Commonwealth of Massachusetts by alleviating transmission constraints typical of moving energy out of Maine" (Companies Reply Brief at 36, citing Exh. EDC-Hearing-4, at 15; Tr. 2, at 350-352).

In addition, the Companies argue that NextEra has failed to offer any forecasts, models, or studies of expected conditions with the NECEC Hydro project in service to support its claim that ISO-NE will require significant additional transmission to address congestion at the Maine-New Hampshire and North-South interfaces (Companies Reply Brief at 37, citing NextEra Brief at 16). In contrast, the Companies argue that their analysis included a detailed representation of the regional transmission topology and historical transmission constraint data that shows the Maine-New Hampshire and North-South interfaces will not limit the delivery of energy from NECEC Hydro into New England (Companies Reply Brief at 37-38, citing Exh. EDC-RB-1, at 42-44). Finally, the Companies assert that ISO-NE currently has not designated Maine as an export-constrained zone but is considering it as potentially export-constrained in the 2023 - 2024 capacity commitment period (Companies Reply Brief at 37-38, citing Exh. EDC-RB-1, at 46). The Companies argue that adding capacity to a potentially export-constrained zone will contribute to resource adequacy in New England (Companies Reply Brief at 38).

3. Analysis and Findings

Pursuant to Section 83D(d), the Department must determine whether NECEC Hydro, a project delivering hydroelectric generation into New England over the new NECEC transmission infrastructure, will provide enhanced electricity reliability within the Commonwealth. See 220 CMR 24.05(1)(a)(1). The Department relies on the Northeast

Power Coordinating Council/North American Electric Reliability Council definition of reliability and has defined "reliability" as the ability to contribute to system resource adequacy and system security. D.P.U. 18-76 through D.P.U. 18-78, at 29; D.P.U. 17-117 through D.P.U. 17-120, at 32; D.P.U. 13-146 through D.P.U. 13-149, at 34; D.P.U. 11-05 through D.P.U. 11-07, at 21; D.P.U. 10-54, at 181.

NECEC will deliver hydroelectric generation over firm transmission service into the New England transmission system at the Larrabee Road substation in Lewiston, Maine (Exhs. JU-4-A at 67; JU-4-B at 67; JU-4-C at 67). In addition, NECEC will interconnect under the Capacity Capability Interconnection Standard and provide transmission system upgrades to allow for firm deliveries into New England at that location (Exhs. JU-1, at 40; EDC-RB-1, at 41-42, 46-48).

The Department has found that, because Massachusetts is part the ISO-NE regional electric system, an improvement in reliability in one area of the regional system will help to bolster the reliability of the system as a whole and this will provide enhanced electricity reliability in Massachusetts. D.P.U. 18-76 through D.P.U. 18-78, at 31; D.P.U. 17-117 through D.P.U. 17-120, at 33-34; D.P.U. 13-146 through D.P.U. 13-149, at 34-35. Here, because Maine is part of the New England regional interconnected electric system, the Department finds that an improvement in reliability in this area of the system will support the reliability of the system as a whole and, thereby, contribute to system resource adequacy and system security support in Massachusetts (Exh. JU-1, at 40).

In addition, the Department has found that resources that contribute to fuel diversity in the region also serve to enhance electricity reliability in Massachusetts. D.P.U. 18-76 through D.P.U. 18-78, at 30-31; D.P.U. 17-117 through D.P.U. 17-120, at 4; D.P.U. 13-146 through D.P.U. 13-149, at 34-35. As a provider of hydroelectric generation, the Department finds that NECEC Hydro will contribute to fuel diversity in New England, thereby enhancing resource adequacy and system security in the region as well as Massachusetts (Exh. EDC-RB-1, at 38).

While NextEra and NEPGA argue that transmission constraints will prevent the flow of additional generation from NECEC Hydro into Massachusetts on an uninterrupted basis, those claims mischaracterize the requirement of Section 83D (see NextEra Brief at 16; NEPGA Brief at 13-14). Contrary to the assertions of NextEra and NEPGA, Section 83D does not require that clean energy generation flow into Massachusetts on an uninterrupted basis.

To demonstrate that a proposed project provides enhanced electricity reliability within Massachusetts, the RFP required bidders to commit any qualifying capacity to ISO-NE exclusively or provide other demonstrations that the proposed project provides enhanced electricity reliability within Massachusetts. As required by the RFP, NECEC Hydro will commit any qualifying capacity to ISO-NE exclusively (Exhs. EDC-RB-1, at 38; EDC-RB-4, at 43).

NextEra also argues that the Companies' production cost model cannot be relied upon to demonstrate that there is a lack of congestion on the Maine-New Hampshire and

North-South interfaces. The Department, however, has found production cost models of the type the Companies used to evaluate bid represent a reasonable method to evaluate the benefits of energy from PPAs for renewable generation. D.P.U. 18-76 through D.P.U. 18-78, at 46; D.P.U. 17-117 through D.P.U. 17-120, at 44; D.P.U. 12-30, at 61. In this case, the Department finds that model used to evaluate the NECEC Hydro project employed reasonable assumptions, including a detailed representation of the regional transmission topology and historical transmission constraint data from 2012 through mid-2017 (Exh. EDC-RB-1, at 42-44). Based on these considerations and our review of the bid evaluation process in Section V, above, the Department finds that the Companies appropriately modeled PPA energy deliveries.

Finally, the Department recognizes that changes in the regional transmission system may occur over time. While the introduction and retirement of generation resources could trigger a need for future transmission upgrades, the Department finds there is no evidence in the record to support NextEra's and NEPGA's claims that NECEC Hydro will require significant transmission upgrades to deliver energy into Massachusetts on a firm basis or that any future transmission upgrades are imminent (see NextEra Brief at 16, NEPGA Brief at 13-14). As discussed above, the Department finds that the Evaluation Team reasonably assessed the transmission topology and electric characteristics of the ISO-NE system with NECEC in service and, consistent with Section 83D(d)(5)(i), NECEC Hydro will deliver energy into New England and Massachusetts (Exhs. JU-6 at 11-12; EDC-RB-1 at 42-43).

For the reasons discussed above, the Department finds that NECEC Hydro will provide enhanced electricity reliability within the Commonwealth as required by Section 83D(d) and 220 CMR 24.05(1)(a)(1).

F. Avoided Line Loss, Mitigated Transmission Costs, Protection from Transmission Cost Overruns

1. Introduction

Pursuant to Section 83D(d), the Department must find that the clean energy generation resource under a long-term contract will avoid line loss, mitigate transmission costs, and ensure that transmission cost overruns are not borne by ratepayers. See also 220 CMR 24.05(1)(a)(4).

2. Positions of the Parties

a. NextEra Energy Resources

NextEra maintains that, to address peak period congestion on the Maine-New Hampshire and North-South transmission interfaces, ISO-NE will require five to ten billion dollars of upgrades that the TSAs do not account for and which will be paid for, in part, by Massachusetts ratepayers (NextEra Brief at 16). NextEra concludes that failure to consider such material upgrade costs invalidates the cost-benefit analysis that underpins the Evaluation Team's selection of the NECEC hydro bid (NextEra Brief at 17).

b. Central Maine Power Company

CMP argues that the pricing structure of the TSAs (i.e., a fixed unit price per kW-month that escalates over each contract year) will ensure that no cost overruns will be passed on to Massachusetts ratepayers (CMP Brief at 8, citing Exhs. JU-1, at 38, 42; JU-4-A at Att. J; JU-4-B at Att. J; JU-4-C at Att. J). In addition, CMP contends that it and the Companies have waived the right to unilaterally seek from FERC any change in TSA prices or other terms and conditions, further protecting ratepayers from any cost overruns that CMP may experience during the development, construction, and operation of NECEC (CMP Brief at 8, citing Exhs. JU-4-A at § 19.1; JU-4-B at § 19.1; JU-4-C at § 19.1). Finally, CMP disputes NextEra's contention that NECEC will require five to ten billion dollars in transmission interface upgrades to deliver energy into New England. CMP argues that NextEra has provided no modeling or other quantitative analysis to support its claims (CMP Reply Brief at 7-8).

c. Companies

The Companies maintain that CMP has performed a conductor optimization study and selected a conductor for NECEC with a higher than typical thermal rating and very low resistance, thereby reducing power losses on the transmission line (Companies Brief at 26, citing Exh. JU-1, at 42). The Companies further contend that the TSAs, as firm, fixed-price contracts, minimize any potential for transmission cost overruns to be passed on to ratepayers (Companies Brief at 26, citing Exhs. JU-1, at 42; NEER 1-23; DPU 2-5).

The Companies maintain that even if ISO-NE determines additional transmission upgrades are required in the future, NextEra is wrong to suggest that Massachusetts ratepayers will be responsible for those costs (Companies Reply Brief at 38, citing Exh. EDC-RB-1, at 46). Instead, the Companies argue that NECEC will be required to resolve any system impacts in the Maine and neighboring load zones, and NECEC will be responsible for the costs associated with the identified system impacts (Companies Reply Brief at 38-39).

3. Analysis and Findings

NextEra asserts that NECEC Hydro will require significant transmission upgrades elsewhere on the New England transmission system at Massachusetts ratepayers' expense and, therefore, does not mitigate transmission costs (NextEra Brief at 18). However, in Section VI.E.3, above, the Department found that three was no evidence to support that NextEra's claims that any such transmission upgrades were imminent or even necessary.

The TSAs provide that CMP will sell firm transmission service on NECEC to the Companies at a fixed price per month to enable the delivery of hydroelectric generation by HQUS into New England (Exh. JU-1, at 37, 42). In addition, under the TSAs, CMP and the Companies have waived any right to seek changes at FERC in transmission prices or other TSA terms and conditions (Exhs. JU-4-A at § 19.1; JU-4-B at § 19.1; JU-4-C at § 19.1). Accordingly, consistent with Section 83D(d), the Department finds that the structure of the TSAs mitigates transmission costs for the clean energy generation resource under contract and ensures that any transmission cost overruns will not be borne by ratepayers. See also 220 CMR 24.05(1)(a)(4).

Finally, the Companies have shown that NECEC will reduce power losses through its use of a conductor with a higher than typical thermal rating and very low resistance (Exh. JU-1, at 42). Accordingly, consistent with Section 83D(d), the Department finds that the clean energy generation resource under contract will avoid line loss.

See also 220 CMR 24.05(1)(a)(4).

G. Project Viability in a Commercially Reasonable Timeframe

1. Introduction

Pursuant to Section 83D(d), the Department must determine whether the clean energy generating resource under a long-term contract adequately demonstrates project viability in a commercially reasonable timeframe. See also 220 CMR 24.05 (1)(a)(7).

2. Positions of the Parties

a. NextEra Energy Resources

NextEra argues that the Companies have provided insufficient evidence that CMP will construct NECEC in a commercially reasonably timeframe (NextEra Brief at 21-22). NextEra maintains that, although the identified in-service date for NECEC is 2022, the contracts are flexible and allow for a delay in commercial operation of up to two years, or even later if the project experiences regulatory approval delays or a force majeure event (NextEra Brief at 21-22, citing Exhs. EDC-RB-l, at 5; NEER l-30; NEER 2-4).

In addition, rather than tracking the status of the NECEC permitting and approval process in real-time, NextEra argues that the Companies only intend to monitor project construction through periodic progress reports provided by CMP (NextEra Brief at 22, citing Exh. NEER 1-26). NextEra asserts that reliance on CMP progress reports is insufficient to show that NECEC will be constructed in a commercially reasonable timeframe (NextEra Brief at 22, citing Exh. NEER-RSW-1, at 38; Tr. 2, at 233). Finally, NextEra argues that the flexibility in NECEC's commercial operation date was not included as a material assumption in the Companies' quantitative evaluation model (NextEra Brief at 23). As a result, NextEra maintains that that any results that model are not valid (NextEra Brief at 22, <u>citing</u> Tr. 1, at 183).

a. <u>Central Maine Power Company</u>

CMP maintains that the commercial operation date for NECEC, as identified in its bid, is December 13, 2022 (CMP Reply Brief at 2, <u>citing</u> Exh. EDC-RB-4). CMP contends that the December 13, 2022, commercial operation date is incorporated in the TSAs (CMP Reply Brief at 2, <u>citing</u> Exhs. JU-4-A at § 4.2; JU-4-B at § 4.2; JU-4-C at § 4.2).

CMP maintains that the TSAs include a project schedule that fully supports the permitting and construction of NECEC by the identified commercial operation date (CMP Reply Brief at 2, <u>citing</u> Exhs. JU-4-A at Att. E; JU-4-B at Att. E; JU-4-C at Att. E). As a means to track its progress, CMP argues that the TSAs require it to provide the Companies with periodic updates to the project schedule, copies of all applications for necessary permits and approvals, and progress reports, including any change in the expected timelines for those permits and approvals (CMP Reply Brief at 2, <u>citing</u> Exhs. JU-4-A at 32-33; JU-4-B at 32-333; JU-4-C at 32-33). Similarly, CMP contends that the PPAs require HQUS to provide progress reports to the Companies regarding NECEC's commercial operation on a quarterly basis, beginning in July 2018 (CMP Reply Brief at 2-3, <u>citing</u> Exhs. JU-3-A at 23; JU-3-B at 25; JU-3-C at 23). Accordingly, CMP argues that it has provided the Companies and HQUS with all required reports and updates to support project viability, and it contends that NECEC is on schedule to be commercially operable by December 13, 2022 (CMP Reply Brief at 3).

Finally, CMP asserts that it has made progress in achieving necessary approvals for NECEC from the Maine Public Utilities Commission ("MPUC"), the Maine Department of Environmental Protection, and the Maine Land Use Planning Commission, including a March 29, 2019 report from the MPUC recommending approval of NECEC's request for a certificate of public convenience and necessity (CMP Reply Brief at 3-4, citing MPUC Docket No. 2017-00232).[64] CMP argues that the NECEC project schedule and CMP's progress towards obtaining the required regulatory approvals in Maine show that NECEC will be constructed in a commercially reasonable timeframe (CMP Reply Brief at 4).

b. Companies

The Companies maintain that the TSAs include a schedule of critical milestones for the development of NECEC (Companies Brief at 27, citing Exhs. JU-1, at 42; JU-4-A at Att. B; JU-4-B at Att. B; JU-4-C at Att. B). The Companies contend that CMP will provide them with notice of the achievement of each critical milestone and, if any milestone is extended, CMP will provide the Companies with an explanation for the delay and the expected impact on the construction schedule and commercial operation date (Companies

64 CMP requests that, pursuant 220 CMR 1.10(2), the Department take official notice of the MPUC report, the forthcoming MPUC final order, and the procedural schedules in certain of the relevant Maine regulatory proceedings (CMP Reply Brief at 4). The Department does not rely on this evidence to support its findings on project viability in a commercially reasonable timeframe. Therefore, the Department need not address CMP's request.

Brief at 27-28, citing Exhs. JU-4-A at 26-28; JU-4-B at 26-28; JU-4-C at 26-28). Further, the Companies maintain that the TSAs require CMP to provide additional credit support to the Companies for any extension of a critical milestone (Companies Brief at 27-28, citing Exhs. JU-4-A at 26-28; JU-4-B at 26-28; JU-4-C at 26-28). The Companies assert that both the TSAs and PPAs include provisions for delay damages if the commercial operation date is not achieved by December 13, 2022 (or later if the date is extended in accordance with the terms of the TSAs) (Companies Brief at 28, citing Exhs. JU-3-A at 22-23; JU-3-B at 24-25; JU-4-C at 22-23; JU-4A at 29; JU-4-B at 29; JU-4-C at 29). Finally, the Companies contend that the HQUS generating resources sources are currently operational and, therefore, will not add any risk to project viability in a commercially reasonable timeframe (Companies Brief at 28, citing Exh. JU-1, at 43).

3. Analysis and Findings

The hydroelectric generating resources under contract are currently operational; however, the NECEC transmission infrastructure to deliver the clean energy generation into New England remains to be built (Exh. JU-1, at 37, 42). Pursuant to the TSAs, the commercial operation date for NECEC is December 13, 2022, with certain allowances for delays (Exh. JU-1, at 39-40).

The TSAs include a schedule of critical milestones to support the development of NECEC by December 13, 2022 (Exhs. JU-1, at 42-43; JU-4-A at Att. B; JU-4-B at Att. B; JU-4-C at Att. B; EDC-RB-l at 5; NEER l-30; NEER 2-4). Further, the TSAs require CMP to provide additional support to the Companies for any extension of a critical milestone

(Exh. JU-1, at 42-43). Finally, the TSAs and PPAs include provisions for delay damages if the commercial operation date is not achieved (Exhs. JU-1, at 43; JU-3-A at 16-17; JU-3-B at 18-19; JU-3-C at 16-17; JU-4-A at 27; JU-4-B at 27; JU-4-C at 27). The Department finds that these contract provisions are designed to ensure that NECEC will be constructed in a commercially reasonable timeframe. Accordingly, consistent with Section 83D(d) and 220 CMR 24.05 (1)(a)(5), the Department finds that the Companies have adequately demonstrated project viability in a commercially reasonable timeframe.

Finally, having found above that the project will be viable in a commercially reasonable timeframe and, given that the PPAs provide delay damages if the commercial operation date is not met, the Department finds that it was reasonable for the Evaluation Team to not include flexibility in commercial operation date as an input in quantitative evaluation model

H. Allowance of Clean Energy Generation to be Paired with Energy Storage

1. Introduction

Pursuant to Section 83D(d), the Department must determine whether the clean energy generating resource under a long-term contract allows for the pairing of energy storage systems. See also 220 CMR 24.05(1)(a)(5).

2. Positions of the Parties

a. H.Q. Energy Services (U.S.)

HQUS asserts that, although the PPAs do not pair the clean energy generation resource with energy storage, the PPAs do not preclude the Companies from pairing the contracted deliveries with storage under separate arrangements (HQUS Brief at 8 n.2).

b. Companies

The Companies maintain that, although the selected bid did not include energy storage, the RFP appropriately allowed bids for resources paired with energy storage (Companies Brief at 27, citing Exhs. JU-1, at 42; DPU 1-5). The Companies further argue that the qualitative evaluation appropriately considered the extent to which bids were paired with energy storage systems (Companies Brief at 27, citing Exhs. EDC-RB-1, at 56; DPU 1-5).

3. Analysis and Findings

The RFP allowed bids pairing energy storage systems with the clean energy generation resource (Exh. JU-2, at 40). As described in Section V.A, above, as part of the qualitative evaluation, the Evaluation Team appropriately considered the extent to which bids were paired with energy storage systems (Exh. DPU 1-5). Although the winning bid and the resulting PPAs do not include energy storage, the PPAs do not preclude the Companies from pairing the contracted deliveries with storage under separate arrangements (Exhs. JU-3-A; JU-3-B; JU-3-C). Accordingly, consistent with Section 83D(d), the Department finds that the clean energy generating resource under long-term contract allows for the pairing of energy storage systems.

I. Employment Benefits and Economic Development

1. Introduction

Pursuant to Section 83D(d), the Department must determine whether the clean energy resource under a long-term contract will create and foster employment and economic development in Massachusetts, where feasible. See also 220 CMR 24.05(1)(a)(8).

2. Positions of the Parties

a. H.Q. Energy Services (U.S.)

HQUS argues that the PPAs will foster employment and economic development in Massachusetts (HQUS Brief at 11). In particular, HQUS asserts that the estimated employment impacts for Massachusetts are, on average, 1,949 jobs per year over the 20-year contract period (HQUS Brief at 11, citing Exhs. EDC-RB-1, at 57; DPU 1-22). HQUS maintains that these employment impacts are a result of the market effects of the PPAs, including lower wholesale electricity prices due to lower LMPs in New England (HQUS Brief at 11-12, citing RR-DPU-1, Att.).

b. Companies

The Companies estimate that NECEC will create or support 10,147 jobs in Massachusetts and New England during development and construction (Companies Brief at 28, citing Exhs. JU-1, at 43; DPU 1-22). The Companies contend that the post-construction estimated employment impacts for Massachusetts are an average of 1,949 jobs per year over the contract term (i.e., 2023 through 2043) (Companies Brief at 28, citing Exh. DPU 1-22; RR-DPU-1). The Companies assert that this number includes full-time and part-time direct and indirect jobs (Companies Brief at 28, citing RR-DPU-1, Att.).

3. Analysis and Findings

The Department has recognized that estimates of employment potential contain uncertainties and actual benefits could be different from projections. D.P.U. 18-76 through D.P.U. 18-78, at 42; D.P.U. 17-117 through D.P.U. 17-120, at 35. Nevertheless, there is no dispute that the construction and operational phases of NECEC will result in additional employment in New England (Exhs. JU-1, at 43; DPU 1-22; RR-DPU-1; RR-DPU-1, Att.). In addition, it is estimated that the project will create additional $213 million in income in Massachusetts (RR-DPU-1; RR-DPU-1, Att.).

As with additional employment, any measures of financial benefit to the economy are only estimates. D.P.U. 18-76 through D.P.U. 18-78, at 42; D.P.U. 17-117 through D.P.U. 17-120, at 35. The construction of NECEC and the long-term PPAs will, however, result in economic benefit for the region totaling an estimated $406.4 million increase in gross domestic product (Exhs. JU-1, at 43; DPU 1-22; RR-DPU-1; RR-DPU-1, Att.). Accordingly, consistent with Section 83D(d) and 220 CMR 24.05(1)(a)(8), the Department finds that NECEC will create and foster employment and economic development in the regional economy.

VII. COST EFFECTIVENESS

A. Introduction

The Department must take into consideration both the potential costs and benefits of the PPAs and TSAs, and we will approve a long-term contract under Section 83D only upon finding that it is a cost-effective mechanism for procuring low cost renewable energy on a long-term basis. Section 83D(a), (b), (d)(5)(iii), (e); 220 CMR 24.05(1). In D.P.U. 10-54, the Department first considered an appropriate standard for evaluating the cost effectiveness of a long-term contract for renewable energy pursuant to St. 2008, c. 169, § 83 ("Section 83"). The Department determined that it would:

> consider in our cost-effectiveness analysis all costs and benefits associated with [a proposed contract], including the non-price benefits that are difficult to quantify, and including costs and benefits of complying with existing and reasonably anticipated future federal and state environmental requirements. . . . In reviewing [the] benefits and costs of [a proposed contract]. . . our focus is on the benefits and costs that accrue to [the company proposing the contract] and its customers.

D.P.U. 10-54, at 71. See also D.P.U. 18-76 through D.P.U. 18-78, at 43. Likewise, Section 83D requires the Department to ensure that long-term contracts are cost effective to electric ratepayers over the term of the contract, taking into consideration the potential economic and environmental benefits to ratepayers. Section 83D(d)(5)(iii), (e); 220 CMR 24.05(1). Accordingly, the Department will evaluate the cost effectiveness of the contracts based on the costs and benefits (both quantitative and qualitative) that the PPAs and TSAs provide.

B. Positions of the Parties

1. Department of Energy Resources

DOER argues that the contracts are a cost-effective method of procuring low cost clean energy generation on a long-term basis (DOER Brief at 5; DOER Reply Brief at 10). DOER maintains that the forecasted benefits of NECEC Hydro exceed its forecasted costs and that, over the term of the contracts, ratepayers will receive an average of 1.6 cents per kilowatt-hour ("kWh") in direct savings (DOER Brief at 6). DOER further maintains that, when indirect benefits are included, NECEC Hydro will provide approximately $4 billion in total net benefits (DOER Brief at 6).

2. H.Q. Energy Services (U.S.)

HQUS argues that the Companies have demonstrated that the contracts are cost-effective for customers (HQUS Brief at 10). In particular, HQUS asserts the Companies have shown that NECEC Hydro will result in $3.962 billion in projected below-market costs (HQUS Brief at 10 citing Exh. JU-1, at 41).

3. Sierra Club

Sierra Club maintains that the Companies have not shown that the proposed contracts are cost-effective mechanisms for procuring low-cost renewable energy on a long-term basis, as required by Section 83D (Sierra Club Brief at 11; Sierra Club Reply Brief at 2). In this regard, Sierra Club argues that the Companies' failure to incorporate safeguards to ensure incremental generation could result in ratepayers paying for incremental hydroelectric generation service without receiving the benefits of that service (Sierra Club Brief at 11).[65]

4. New England Power Generators Association

NEPGA argues that the PPAs are not cost-effective for Massachusetts ratepayers (NEPGA Reply Brief at 12). In particular, NEPGA argues that when the five to ten billion dollars in additional transmission upgrades needed to ensure that the energy from NECEC Hydro flows into Massachusetts are factored into the analysis, the contracts are not cost effective (NEPGA Reply Brief at 12-13).

5. NextEra Energy Resources

NextEra maintains that, to address peak period congestion on these two interfaces, ISO-NE will require five to ten billion dollars of upgrades that the TSAs do not account for and which will be paid for, in part, by Massachusetts ratepayers (NextEra Brief at 16). NextEra concludes that failure to consider such material upgrade costs invalidates the cost-benefit analysis that underpins the Evaluation Team's selection of the NECEC Hydro bid (NextEra Brief at 17).

6. Central Maine Power Company

CMP argues that the NECEC Hydro project is cost-effective to ratepayers over the term of the contracts (CMP Brief at 6). CMP maintains that the project will provide cost-reduction benefits through firm, fixed--price electricity and attractive financing terms

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65 Sierra Club's arguments concerning incremental hydroelectric generation are addressed in Section VI.B.2, below.

(CMP Brief at 6-7, citing Exh. JU-1, at 41, 44). CMP further maintains that the project provides significant environmental benefits that will help ensure the Commonwealth's GWSA goals reach fruition (CMP Brief at 7).

7. Companies

The Companies argue that the contracts will be cost-effective for customers over the term (Companies Brief at 25; Companies Reply Brief at 31-32). In this regard, the Companies assert that, over the term of the contracts, an estimated $3.962 billion in net benefits will accrue to Massachusetts ratepayers (Companies Brief at 26).

C. Analysis and Findings

As described in Section V, above, to develop net benefits estimates, the Companies retained a consultant to evaluate the costs and benefits of the proposals received in response to the clean energy generation RFP (Exh. JU-6, at 3). The consultant employed a computer model to (1) calculate the delivered cost of energy and environmental attributes under the PPAs and TSAs and (2) forecast the market value of energy and environmental attributes under the Section 83D base case, for each proposal case, and for several portfolio cases (Exh. JU-6, at 8-9). These forecasts form the basis of the Evaluation Team's assessment of the net benefits associated with the individual proposals and the portfolio cases. Therefore, in order to determine whether the Companies' estimates of quantifiable net benefits are reasonable, the Department must evaluate whether the price forecasts and the market revenue estimates derived from the forecasts are reasonable. D.P.U. 18-76 through D.P.U. 18-78, at 45-56, citing D.P.U. 10-54, at 108. To do so, the Department must determine whether the forecasts are a reasonable projection of energy and environmental attribute value. See D.P.U. 18-76 through D.P.U. 18-78, at 46, citing D.P.U. 10-54, at 108.

The Companies applied an energy market production cost and system expansion optimization model to develop their market forecasts of energy and REC/CEC prices, including analysis of (1) demand requirements, (2) capacity expansion, (3) pricing for fuel, emissions, RECs, and CECs, (4) transmission topology, (5) load forecasts, and (6) small proposal impacts (Exhs. JU-6, at 8-14).[66] As the Department has found previously, this type of analysis is valid for evaluating the benefits of energy from long-term contracts for renewable generation. D.P.U. 18-76 through D.P.U. 18-78, at 46; D.P.U. 17-117 through D.P.U. 17-120, at 44; D.P.U. 12-30, at 61. In addition, this method is consistent with the approach described in the RFP and employed in previous reviews of long-term contracts (Exh. JU-2, at 7-11). D.P.U. 18-76 through D.P.U. 18-78, at 46; D.P.U. 17-103, at 33-34; D.P.U. 17-117 through D.P.U. 17-120, at 44. Accordingly, because the energy and REC/CEC market price forecasts used by the Companies to evaluate the proposals rely upon well-established and appropriate methods, the Department finds that such forecasts result in reasonable market revenue estimates for these products.

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66 The computer model contained assumptions about various energy market factors, including (1) generating unit capacity additions, (2) transmission, (3) load forecast; (4) installed capacity requirements, (5) RPS requirements, (6) CES and carbon emissions caps, (7) emissions allowance prices, (8) generating unit retirements, (9) generating unit operational characteristics, and (10) fuel prices (Exh. JU-6, at 8-14). The Department has reviewed the various assumptions underlying the model and finds them to be reasonable.

In order for the Department to determine whether the contracts are cost-effective over the life of the proposed contracts, the Department must compare the estimated costs and benefits of the contracts. D.P.U. 18-76 through D.P.U. 18-78, at 46-47; D.P.U. 17-117 through D.P.U. 17-120, at 45; D.P.U. 13-146 through D.P.U. 13-149, at 40; D.P.U. 11-05 through D.P.U. 11-07, at 28, citing D.P.U. 10-54, at 79. The Companies estimate the cost of energy, environmental attributes, and transmission under each contract by multiplying the projected quantity of delivered products by the contractually specified schedule of energy and environmental attribute prices and adding transmission payments, taking into consideration that the contracts provide for annual escalating prices over the contract terms (Exhs. JU-1, at 26-27; JU-3-A at Exhibit D; JU-3-B at Exhibit D; JU-3-C at Exhibit D; JU-4-A at Att. J; JU-4-B at Att. J; JU-4-C at Att. J; JU-6, at 5). Based on the forecasted market prices of energy and CECs and estimated production of the facilities, the Companies estimate that the total cost of the energy and environmental attributes will be below the market value of energy and CECs over the term of the contracts by a value of $3.962 billion (nominal) (Exh. JU-1, at 41).

NextEra and NEPGA argue five to ten billion dollars in additional transmission upgrades are needed to ensure that the energy from NECEC Hydro flows into Massachusetts and, when these additional costs are factored into the analysis, the contracts will no longer be cost effective (NextEra Brief at 16-17; NEPGA Reply Brief at 12-13). As the Department addressed in Section VI.E.3, above there is no evidence in the record to support the claim that future transmission upgrades are imminent (see NextEra Brief at 16, NEPGA Reply

Brief at 12-13). Accordingly, the Department finds that the Companies appropriately declined to include these costs when considering the estimated costs and benefits of the contracts.

In order to determine whether a contract is a cost-effective mechanism for procuring low cost renewable energy on a long-term basis, the Department also considers whether additional qualitative benefits will accrue to the Companies' ratepayers over the term of each contract. D.P.U. 18-76 through D.P.U. 18-78, at 47; D.P.U. 17-117 through D.P.U. 17-120, at 46; D.P.U. 13-146 through D.P.U. 13-149, at 39. As described in Section V, above, a number of qualitative benefits have been identified as accruing to ratepayers over the term of the proposed contracts, including benefits related to reliability, environmental impacts, employment, and economic development (Exh. JU-2, at 39-41).

Based on the discussion above, the Department finds that the Companies have demonstrated there are significant net benefits to ratepayers associated with the instant contracts (i.e., the Companies have shown that NECEC Hydro will produce benefits to ratepayers that will exceed the costs of the contracts) (Exh. JU-1, at 41). In particular, the Companies have shown that the aggregate delivered cost for energy and environmental attributes under the contracts are less than the forecasted market prices for delivered energy and CECs by $3.962 billion (nominal) over the life of the contracts (Exh. JU-1, at 41). The Department further finds that significant qualitative benefits will flow to ratepayers under the contracts in the areas of reliability, mitigated environmental impacts, and economic development (Exh. JU-1, at 29-30, 40-44). Accordingly, after taking into consideration both the potential costs and benefits of the PPAs and TSAs, the Department finds that the contracts are a cost-effective mechanism for procuring low cost[67] renewable energy on a long-term basis. Section 83D; 220 CMR 24.05(1).

VIII. PUBLIC INTEREST

A. Introduction

In Section VII, below, the Department found that the proposed contracts will be cost-effective to ratepayers over the terms. However, a finding that the contracts will be cost-effective does not necessarily mean that the proposed contracts are in the interest of ratepayers and, therefore, in the public interest. See, e.g., D.P.U. 18-64 through D.P.U. 18-66, at 48; D.P.U. 17-117 through D.P.U. 17-120, at 50; D.P.U. 13-146 through D.P.U. 13-149, at 57; D.P.U. 12-98, at 24; D.P.U. 11-05 through D.P.U. 11-07, at 39, citing D.P.U. 10-54, at 65. The Department reviews the public interest of long-term contracts for renewable energy based on the specific facts and circumstances relevant to each proposed contract. D.P.U. 18-76 through D.P.U. 18-78, at 48-49; D.P.U. 17-117 through D.P.U. 17-120, at 50; D.P.U. 13-146 through D.P.U. 13-149, at 57; D.P.U. 12-98, at 24; D.P.U. 11-05 through D.P.U. 11-07, at 39; D.P.U. 10-54, at 65-66.

Here, as part of our evaluation of whether the contracts are in the public interest, the Department will consider whether the pricing terms in the contracts are reasonable for clean energy generation resources. See D.P.U. 18-76 through D.P.U. 18-78, at 49; D.P.U. 17-117 through D.P.U. 17-120, at 50; D.P.U. 13-146 through D.P.U. 13-149, at 57;

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[67] In Section VII.C, above, the Department found that the contracts are low cost.

NSTAR Electric Company, D.P.U. 12-98, at 25 (2013); D.P.U. 11-05 through D.P.U. 11-07, at 39; D.P.U. 10-54, at 217. The Department will also consider whether other, lower cost Section 83D-eligible resources were available to the Companies and, if so, whether the benefits of the proposed contracts justify any higher costs. See D.P.U. 18-76 through D.P.U. 18-78, at 49; D.P.U. 17-117 through D.P.U. 17-120, at 50; D.P.U. 13-146 through D.P.U. 13-149, at 57; D.P.U. 11-05 through D.P.U. 11-07, at 39; D.P.U. 10-54, at 217.

In addition, to determine whether the contracts are in the public interest, the Department will assess the reasonableness of the Companies' decision to enter into contracts of the given size. See, e.g., D.P.U. 18-76 through D.P.U. 18-78, at 49; D.P.U. 17-117 through D.P.U. 17-120, at 50-51; D.P.U. 13-146 through D.P.U. 13-149, at 57-58; D.P.U. 12-98, at 25; D.P.U. 11-05 through D.P.U. 11-07, at 39; D.P.U. 10-54, at 217. Finally, the Department will consider whether the bill impacts of the contracts are reasonable in light of the benefits of the contracts. See, e.g., D.P.U. 18-76 through D.P.U. 18-78, at 49; D.P.U. 17-117 through D.P.U. 17-120, at 50-51; D.P.U. 13-146 through D.P.U. 13-149, at 57-58; D.P.U. 12-98, at 25; D.P.U. 11-05 through D.P.U. 11-07, at 39; D.P.U. 10-54, at 217.

B. Positions of the Parties

1. Department of Energy Resources

DOER contends that the PPAs were the result of a bid evaluation process that was overseen by an Independent Evaluator (DOER Brief at 9). DOER notes that the Independent

Evaluator concluded that (1) the quantitative and qualitative bid evaluations were conducted in a fair and objective manner, (2) the evaluation criteria in were applied equally to all bidders, (3) the evaluation process complied with the terms of the RFP and satisfied guidelines for solicitations where affiliates were bidders, and (4) all bids were evaluated in a fair and non-discriminatory manner (DOER Brief at 9-10, citing Exh. IE Report at 2, 49, 54-55). DOER argues that the Independent Evaluator's findings show that the PPAs are the product of an open, fair, and transparent solicitation process and, therefore, in the public interest (DOER Brief at 10).

In addition, DOER maintains that it served in an advisory role during the bid selection process (DOER Brief at 11). DOER argues that the bid evaluation and selection process complied with all requirements established in the RFP (DOER Brief at 11).

DOER argues that the PPAs are the result of a robust and highly competitive solicitation that produced 53 distinct bid proposals from across New England and adjacent control areas (DOER Brief at 11-12, citing Exh. DOER-1, at 2). DOER contends that the PPAs will provide benefits of approximately $4 billion in addition to low-cost environmental attributes that will assist the Commonwealth in meeting its GWSA goals (DOER Brief at 12, citing Exhs. JU-7, at 2; DOER-1, at 3). DOER maintains that ratepayers will receive the GWSA compliance benefit because the environmental attributes will be secured through PPAs and retired pursuant to Section 83D (DOER Brief at 12). In total, DOER argues that the PPAs will produce a positive net benefit of more than four cents per kWh for ratepayers (DOER Brief at 12, citing Exh. JU-6, at 25). With regard to bill impacts, DOER maintains that the PPAs are projected to reduce customers' monthly bills by approximately two to four percent (DOER Brief at 12, citing Exh. JU-11). DOER argues that these bill impacts are reasonable because they will result in savings to ratepayers over the life of the contracts (DOER Brief at 12). Therefore, DOER argues that the PPAs satisfy the public interest standard and should be approved (DOER Brief at 12).

2. H.Q. Energy Services (U.S.)

HQUS contends that the PPAs are in the public interest because they are low cost and reasonable in comparison to the alternatives (HQUS Brief at 12). HQUS maintains that NECEC was selected through an open, robust competitive bid process approved by the Department. (HQUS Brief at 12, citing Exh. JU-1, at 41). HQUS also maintains that the bid selection and negotiation process were conducted fairly and that the Department should find that the selection of NECEC was reasonable (HQUS Brief at 12-13).

3. Companies

The Companies maintain that the RFP was widely distributed to approximately 600 entities active in the renewable generation market (Companies Brief at 25, citing Exhs. JU-1, at 21, 41; WP Support Tab A; IE Report at 37). The Companies argue that (1) the solicitation process was fairly administered, (2) the results were evaluated against a common market price forecast, and (3) the PPAs will provide $3,962 million in projected savings to ratepayers in Massachusetts (Companies Brief at 26, citing Exhs. JU-1, at 41; IE Report at 39). For these reasons, the Companies argue that the PPAs are in the public interest (Companies Brief at 25).

C. Analysis and Findings

As described above, in order to determine whether the contracts are in the public interest, the Department will consider: (1) whether the pricing terms in the contracts are reasonable for clean energy generation resources; (2) whether other, lower cost Section 83D-eligible resources were available to the Companies and, if so, whether the benefits of the proposed contracts justify any higher costs; (3) the reasonableness of the Companies' decision to enter into contracts of the given size; and (4) whether the bill impacts of the contracts are reasonable in light of the benefits of the contracts. See, e.g., D.P.U. 18-76 through D.P.U. 18-78, at 52; D.P.U. 17-117 through D.P.U. 17-120, at 50-51, 56-60; D.P.U. 13-146 through D.P.U. 13-149, at 57-58; D.P.U. 12-98, at 25; D.P.U. 12-30, at 167; D.P.U. 11-05 through D.P.U. 11-07, at 39; D.P.U. 10-54, at 217, 265, 274.

As described in Section V, above, the Companies procured the contracts through a competitive solicitation process (Exh. JU-1, at 41). The Department has determined that a properly conducted competitive solicitation provides a direct comparison of the costs and benefits of alternative resources, as well as some assurance that the price is not too high for a given resource. D.P.U. 18-76 through D.P.U. 18-78, at 52-53; D.P.U. 17-117 through D.P.U. 17-120, at 56; D.P.U. 13-146 through D.P.U. 13-149, at 58, citing D.P.U. 12-98, at 25, D.P.U. 11-05 through D.P.U. 11-07, at 39, citing D.P.U. 10-54, at 66-67. The Department has further found that a competitive bidding and qualification process provides an objective benchmark for analyzing the reasonableness of price. See D.P.U. 18-76 through

D.P.U. 18-78, at 53; D.P.U. 10-114, at 221, citing Bay State Gas Company, D.P.U. 09-30, at 228-229 (2009); Fitchburg Gas and Electric Light Company, d/b/a Unitil, D.P.U. 07-71, at 101 (2008); Boston Gas Company, d/b/a KeySpan Energy Delivery New England, D.T.E. 03-40, at 152 (2003).

In Section V, above, the Department found that the Companies conducted an open, fair, and transparent competitive solicitation that was consistent with the requirements of Section 83D and the method approved by the Department in D.P.U. 17-32. Through this solicitation process, the Companies entered into contracts with the proposal that received the highest score and rank among all proposals evaluated (Exh. JU-6, at 17, 24). Relying on the objective benchmark provided by the properly conducted competitive solicitation process, the Department finds that the pricing terms in the contracts are reasonable for clean energy generation resources. See D.P.U. 18-76 through D.P.U. 18-78, at 53; D.P.U. 17-117 through D.P.U. 17-120, at 50; D.P.U. 13-146 through D.P.U. 13-149, at 57; D.P.U. 12-98, at 25; D.P.U. 11-05 through D.P.U. 11-07, at 39; D.P.U. 10-54, at 217.

In addition, the Companies selected the proposal that scored highest on price factors (Exh. JU-6, at 24-25). Therefore, the Department finds that NECEC Hydro is a low-cost clean energy generation resource and that there were no lower cost Section 83D-eligible resources available to the Companies. See D.P.U. 18-76 through D.P.U. 18-78, at 53-54; D.P.U. 17-117 through D.P.U. 17-120, at 50; D.P.U. 13-146 through D.P.U. 13-149, at 57; D.P.U. 11-05 through D.P.U. 11-07, at 39; D.P.U. 10-54, at 217.

With regard to the reasonableness of the Companies' decision to enter into contracts of the given size, Section 83D requires the Companies to jointly conduct one or more competitive solicitations for clean energy generation equal to approximately 9,450,000 MWh by December 31, 2022. Section 83D(b); 220 CMR 24.04(5). The Companies, in conjunction with DOER, issued the RFP prior to the deadline established in Section 83D(a) (i.e., prior to April 1, 2017) (Exh. JU-1, at 18).

In D.P.U. 17-32, at 94, the Department approved the solicitation of proposals for approximately 9,450,000 MWh of clean energy generation annually, finding that this was consistent with Section 83D and 220 CMR § 24.04(5). D.P.U. 17-32, at 94. Here, the Companies have submitted contracts for the aggregate annual purchase of 9,554,940 MWh of clean energy generation (Exh. JU-1, at 36). Although the instant solicitation resulted in proposed contracts exceeding 9,450,000 MWh, we find that it was reasonable for the Companies to contract for 9,554,940 MWh of clean energy generation annually based on the competitiveness of the NECEC Hydro bid and the level of economic net benefits to ratepayers (see Section VII.C, above).

Finally, the Companies provided estimated bill impacts of the contracts, based on the current market environment (Exhs. JU-1, at 58; JU-11). In particular, the Companies provided bill impacts for each rate class and for a range of different consumption levels within each rate class (Exh. JU-11). Based on the current market environment, the Companies project that the contracts will result in overall net bill savings for ratepayers over the life of the contracts (Exh. JU-11). After review, the Department finds that the bill impacts of the contracts are reasonable in light of the benefits of the contracts.

In conclusion, through the use of a fair, open, and transparent competitive solicitation process, the Companies have demonstrated that (1) the pricing terms in the contracts are reasonable for clean energy generation resources and (2) the contracts are low-cost and there were no other lower-cost Section 83D-eligible resources available to the Companies. In addition, the Department finds that it was reasonable for the Companies to contract for 9,554,940 MWh of clean energy generation based on the competitiveness of the bid and the level of economic net benefit to ratepayers. Finally, the Department finds that the estimated bill impacts of the contracts are reasonable in light of the benefits of the contracts. For these reasons, the Department finds that the contracts are in the public interest.

IX. REMUNERATION

A. Introduction

Section 83D provides that an electric distribution company shall receive remuneration up to 2.75 percent of the annual payments under a long-term contract, to compensate the company for accepting the financial obligation of the long-term contract. See also 220 CMR 24.07. Each electric distribution company proposes to collect annual remuneration equal to 2.75 percent of the annual payments under the PPAs and TSAs (Exh. JU-1, at 45).

B. Positions of the Parties

1. Attorney General

The Attorney General argues that Section 83D does not require the Department to set the remuneration rate at any particular level; rather, the statute obligates the Department to set an appropriate remuneration level, if any, up to 2.75 percent based upon its review of the evidence presented (Attorney General Reply Brief at 2-5). The Attorney General maintains that the Companies bear the burden to support their remuneration request (Attorney General Brief at 9-10). The Attorney General emphasizes that the words "up to" in Section 83D specifically obligate the Companies to provide quantitative support for their proposed remuneration rate (Attorney General Reply Brief at 2-5). The Attorney General asserts that the Companies inappropriately attempt to shift the burden of proof to the Department with their argument that the Department may establish a remuneration rate of less than 2.75 percent only upon a finding of extenuating circumstances (Attorney General Reply Brief at 3, citing Companies Brief at 2, 38). The Attorney General observes that in jurisdictions where discretionary remuneration has been legislatively authorized, the public utility commission having discretion to grant a remuneration request have denied all such requests (i.e., Oklahoma, Oregon, Hawaii) and that the examples of Rhode Island and Virginia cited by the Companies in discovery responses did not occur in the context of discretionary remuneration (Attorney General Brief at 11 n.11).

The Attorney General argues that the Companies have failed to meet their burden to support their 2.75 percent remuneration requests (Attorney General Brief at 8-10, 12-13). In this regard, the Attorney General asserts that the Companies have not attempted to quantify the cost of the financial obligation arising from the PPAs and TSAs (Attorney General Brief at 8; Attorney General Reply Brief at 9-10). The Attorney General argues that the Companies have failed to show that they will incur any incremental obligation-related costs associated with the contracts because they are assured full and timely cost recovery in rates (Attorney General Brief at 10). As support, the Attorney General maintains that there is no evidence that the Companies have incurred any cost recovery-risk with previous long-term renewable energy contracts (Attorney General Reply Brief at 16-17). The Attorney General further argues that the Companies have failed to demonstrate that these contracts will negatively impact their returns on equity or credit quality and, in particular, have provided no evidence from credit rating agencies showing that the contracts will impair their credit ratings (Attorney General Brief at 13-15; Attorney General Reply Brief at 11).[68] Finally, the Attorney General argues that the Companies have failed to support their claim that the credit rating agencies view remuneration as integral to the Commonwealth's credit-supportive regulatory environment (Attorney General Brief at 14).

The Attorney General rejects the Companies' assertion that there is no existing or accepted method for quantifying the impact of the Companies' acceptance of the financial obligations of the PPAs and TSAs (Attorney General Brief at 10-12). The Attorney General

68 For example, the Attorney General asserts that there is no evidence the credit rating agencies have imputed debt to the Companies' balance sheets associated with Section 83 long-term contracts (Attorney General Brief at 15).

cites the Standard and Poor's ("S&P") imputed debt method as an appropriate and accepted approach for quantifying the financial obligations of a contract (Attorney General Brief at 10-12). According to the Attorney General, the S&P imputed debt method calculates the net present value of the contract capacity payments and then adjusts that value by a factor tied to the risk of cost recovery (Attorney General Brief at 10-11). The Attorney General maintains that because the Companies are assured full and timely recovery of contract costs in rates, the risk factor in this case is close to zero (Attorney General Brief at 10; Attorney General Reply Brief at 12). On this basis, the Attorney General argues that remuneration should be minimal, if any (Attorney General Brief at 10).

The Attorney General also challenges the validity of the Companies' attempt to link their remuneration requests to an analysis of the net benefits to ratepayers from the PPAs and TSAs (Attorney General Brief at 15-16). The Attorney General argues that an analysis of ratepayer benefits is not relevant to the legislatively prescribed standard for setting the remuneration rate (Attorney General Brief at 15-16; Attorney General Reply Brief at 9).

The Attorney General agrees with the Companies' assertion that credit ratings take into consideration a broad range of regulatory and business considerations, but she argues that the Companies have offered no evidence that remuneration specifically is critical to the rating agencies' assessment of the Commonwealth's supportive regulatory environment (Attorney General Brief at 13-15). In support of this position, the Attorney General maintains that the Companies have offered no evidence to suggest that the statutory reduction in the remuneration rate from 4.00 percent in Section 83 to 2.75 percent in St. 2008, c. 169,

§ 83A, as amended by St. 2012, c. 188, § 12 (“Section 83A”) affected the credit rating agencies’ assessment of the Commonwealth’s regulatory environment (Attorney General Brief at 14-15).

2. Conservation Law Foundation

CLF contends that the Legislature set a remuneration cap of no more than 2.75 percent, leaving it to the Department’s discretion whether, and if so, how much remuneration the Companies should receive “to compensate the [Companies] for accepting the financial obligations of the [contracts]” (CLF Brief at 10). CLF argues that the Companies have not met their burden to support their request for a remuneration rate equal to 2.75 percent and, therefore, the remuneration rate should be at or near zero (CLF Brief at 10-11; CLF Reply Brief at 1-3). CLF claims that the Companies have provided no evidence or testimony that they incur any material or quantifiable financial risk in connection with the contracts that justifies compensation (CLF Brief at 10-11).

CLF supports the use of the S&P imputed debt method as a reasonable proxy for the financial obligations that the Companies will incur with these contracts (CLF Brief at 11). CLF maintains that using the S&P method, the financial burden that the contracts place on the Companies is readily quantifiable and at or near zero (CLF Brief at 11-12). In support, CLF argues that the Companies will be fully compensated for all costs they incur in relation to their participation in and execution of the Section 83D contracts (CLF Brief at 11).

3. The Energy Consortium

TEC argues that the Department should avoid setting a fixed remuneration rate at 2.75 percent and, instead, should adopt a variable rate that would change based upon the Companies' actual working capital needs (TEC Reply Brief at 1-3). TEC maintains that there is precedent for recovery of working capital needs with the basic service administration adder (TEC Reply Brief at 3).

TEC argues that the 2.75 percent rate represents a cap on remuneration that the Department can authorize if the Companies have met their burden to show that the maximum percentage permitted pursuant to Section 83D is warranted under the circumstances (TEC Reply Brief at 1-2). TEC maintains that while the Companies have qualitatively described the working capital needs associated with these contracts, they have not demonstrated that working capital needs justify a 2.75 percent remuneration level (TEC Reply Brief at 3). TEC argues that it is unreasonable for the Department to commit a significant amount of ratepayer funds for remuneration over the next 20 years based on speculation (TEC Reply Brief at 4).

4. Western Massachusetts Industrial Group

WMIG maintains that the Companies have not supported the maximum remuneration rate that they seek (WMIG Brief at 4). WMIG argues that the Companies' arguments rely on qualitative or speculative evidence that is not sufficient information for the Department to set a remuneration rate (WMIG Brief at 4).

WMIG challenges the Companies' position that the maximum remuneration is supported by Department precedent (WMIG Brief at 5; WMIG Reply Brief at 4). WMIG argues that the Legislature has moved away from setting a fixed mandatory remuneration percentage in Section 83D, which means that the statutory basis underlying past remuneration awards no longer exists (WMIG Brief at 5; WMIG Reply Brief at 4). Further, in response to the Companies' argument that any remuneration rate less than 2.75 percent signals instability and may have negative future impacts for the Companies, WMIG argues that the Legislature previously has reduced the remuneration percentage from 4.00 percent to 2.75 percent and there was no showing that this change negatively impacted the Companies (WMIG Brief at 5; WMIG Reply Brief at 4).

WMIG argues that the remuneration approach used in Rhode Island and Virginia does not support the maximum remuneration requested under Section 83D because the statutory basis for remuneration is different in Massachusetts (WMIG Brief at 6). Lastly, WMIG argues that while the PPAs and TSAs will advance important public policy goals (i.e., addressing climate change and emission reductions), these factors are not a basis upon which the Department is to establish the remuneration rate (WMIG Reply Brief at 4).

5. Companies

The Companies argue that their proposal to apply a remuneration rate equal to 2.75 percent is consistent with the "strategic paradigm" for the Commonwealth reflected in the Green Communities Act (Companies Brief at 29-34). In particular, the Companies argue that Section 83D is intended to support the development of clean energy generation resources to help achieve the Commonwealth's greenhouse gas reduction goals (Companies Brief at 32-33). The Companies maintain that having strong credit enables them to enter into cost-effective contracts that facilitate the development of new clean energy resources (Companies Brief at 30-31). The Companies further maintain that their strong credit is secured through remuneration plus full and timely recovery of contract costs (Companies Brief at 33-34).

The Companies assert that the Legislature intended remuneration as a means to avoid potential harm to electric distribution company credit quality associated with long-term renewable energy contract obligations (Companies Brief at 40-45; Companies Reply Brief at 46-49). The Companies argue that remuneration provides the financial markets with an essential signal that the Commonwealth is committed to support clean energy generation for the long term (Companies Brief at 28-34, 37, 57-60; Companies Reply Brief at 64). The Companies argue that regulatory consistency is of critical importance in credit rating agencies' assessment of a supportive regulatory environment (Companies Brief at 48-51). The Companies maintain that a departure from a 2.75 percent remuneration rate would send a negative signal to the financial markets that the Commonwealth's regulatory environment is weakening at the same time that the Companies' financial obligations related to long-term renewable energy contracts are growing (Companies Brief at 49).

In addition, the Companies assert that the financial obligations of the PPAs and TSAs create considerable business and financial risks (Companies Brief at 44-48; Companies Reply Brief at 46-49). The Companies argue that the Legislature has consistently recognized that they are entitled to recover remuneration to compensate them for assuming financial obligations of long-term renewable energy contracts (Companies Brief at 29, 33-34). The Companies maintain that the Section 83D contracts represent a significant increase in the magnitude of their purchase commitments and the cumulative effect of these long-term obligations could ultimately have an adverse impact on their financial positions (Companies Brief at 31-34).

The Companies also cite contract cost recovery risk as a factor supporting their remuneration request (Companies Brief at 50-51). The Companies claim that (1) market-price risk exposure and (2) timing differences between net payments under the PPAs and TSAs and the collection of contract costs from ratepayers, create working capital requirements that will require them to increase short-term borrowing (Companies Brief at 51). The Companies further argue that cash flow will be an important consideration for investors when the Companies begin to incur financial obligations under the PPAs and TSAs (Companies Brief at 51-52; Companies Reply Brief at 61-62, 68).

The Companies argue that Section 83D provides the Department with discretion to determine the level of remuneration that is appropriate to compensate the Companies for the financial obligations and other risks associated with the PPAs and TSAs (Companies Brief at 34, 38-42). The Companies maintain, however, that there are no extenuating circumstances sufficient to warrant a remuneration level below 2.75 percent in these cases (Companies Brief at 60).

The Companies disagree with intervenors' arguments that the words "up to" in Section 83D mandate a quantitative approach to determining remuneration level (Companies Reply Brief at 57, citing Attorney General Brief at 9). In particular, the Companies reject intervenors' arguments that Section 83D requires them to demonstrate that they experience quantified contract cost-recovery risk in order to qualify for remuneration (Companies Reply Brief at 45, 64-66). Further, the Companies reject the Attorney General's claim that there is a single best method for determining the financial obligation incurred by the Companies under the PPAs and TSAs for the purpose of setting the remuneration rate (Companies Brief at 38-39, 42-43). The Companies argue that there are a number of potentially relevant considerations for determining financial obligation (Companies Brief at 46).

In this regard, the Companies argue that there is no basis for the Department to rely on S&P's imputed debt method to set a remuneration rate, as suggested by the Attorney General (Companies Reply Brief at 63-64, 66-70). The Companies maintain that it is not appropriate for the Attorney General to determine whether and how to apply the imputed debt method to the specific circumstances of the PPAs and TSAs where there is no evidence that the credit-ratings agencies will evaluate the impact of the financial obligations associated with the PPAs exclusively through a PPA-specific inquiry (Companies Reply Brief at 54, 60-62, 69-70). Further, the Companies challenge the Attorney General's assertion that the S&P imputed debt method is the most accepted method by which the credit rating agencies quantify the financial obligations associated with long-term contracts (Companies Reply Brief at 66-68). The Companies assert that the two other major credit rating agencies (i.e., Moody's and Fitch Group) do not use the S&P imputed debt method and that S&P, itself, does not consider its imputed debt analysis to be an established methodology (Companies Reply Brief at 66-67).

Finally, the Companies argue that an analysis of ratepayer net benefits associated with the contracts provides quantitative support for their remuneration request (Companies Reply Brief at 72-74). The Companies maintain that their strong balance sheets and credit ratings enable them to enter into highly cost-effective contracts, even with 2.75 percent annual remuneration (Companies Reply Brief at 46, 55, 73). In this regard, the Companies argue that the Department could set the remuneration rate as high as 21.81 percent and the PPAs would still be cost-effective (Companies Reply Brief at 73).

C. Analysis and Findings

Under Section 83D, the Department shall provide for annual remuneration up to 2.75 percent of the annual payments under the contract to compensate the electric distribution company for "accepting the financial obligation of the long-term contract." See also, 220 CMR 24.07. The Companies propose to collect remuneration of 2.75 percent of the annual payments under the PPAs and TSAs, arguing that this level of remuneration is appropriate compensation for accepting the financial risk of the contracts and provides an important signal of the Commonwealth's continued commitment to support the clean energy generation necessary to achieve greenhouse gas emissions reduction goals (Exh. JU-1, at 45, 49-51). The Attorney General and other intervenors maintain, however, that the Companies have failed to meet their burden to demonstrate that a remuneration rate of 2.75 percent is reasonable (see, e.g., Attorney General Brief at 8-10, 12-13; CLF Brief at 10; CLF Reply Brief at 1-3; TEC Reply Brief at 3; WMIG Brief at 4).

Recently, the Department for the first time had to exercise its discretion to determine the appropriate level of remuneration to compensate an electric distribution company for accepting the financial obligation of a long-term renewable energy contract. D.P.U. 18-76 through D.P.U. 18-78; Long Term Contracts for Offshore Wind Energy Generation Pursuant to Section 83C, D.P.U. 18-76-A through D.P.U. 18-78-A (May 31, 2019). In prior renewable energy contract matters, the level of remuneration was set by the Legislature as "equal to" a certain amount (i.e., 4.00 percent under Section 83 and 2.75 percent under Section 83A), which left no role for Department discretion in establishing a remuneration rate. D.P.U. 18-76 through D.P.U. 18-78, at 67 & n.41 citing D.P.U. 10-54, at 316-317; D.P.U. 17-117 through D.P.U. 17-120, at 63.

Like Section 83C, Section 83D tasks the Department to determine what level of annual remuneration, up to 2.75 percent, is appropriate to compensate the Companies for accepting the financial obligation of a long-term contract. In D.P.U. 18-76 through D.P.U. 18-78, at 72-73, and like Section 83C, Section 83D is silent on what factors the Department should weigh in its determination. Therefore, when setting the appropriate level of remuneration in this Order, the Department again acts on an explicit grant of authority and within its purview to exercise its judgment-. D.P.U. 18-76 through D.P.U. 18-78, at 68 n.42; See Craft Beer Guild, LLC v. Alcoholic Beverages Control Comm'n., 481 Mass. 506, 520 (2019), quoting Taylor v. Housing Appeals Comm., 451 Mass. 149, 153-154 (2008) (deference to agency resolution appropriate where there is a "gap in the statutory guidance"); Franklin Office Park Realty Corp. v. Comm'r of Dep't of Envtl. Prot., 466 Mass. 454, 460 (2013) quoting Brookline v. Comm'r of the Dep't of Envtl. Quality Eng'g, 398 Mass. 404, 414 (1986) (disturbing an agency's interpretation of its statutory mandate only if it is "patently wrong, unreasonable, arbitrary, whimsical, or capricious"); Zoning Bd. of Appeals of Amesbury v. Housing Appeals Comm., 457 Mass. 748, 760 (2010) quoting Goldberg v. Bd. of Health of Granby, 444 Mass. 627, 633 (2005) ("[S]tate administrative agency in Massachusetts has considerable leeway in interpreting a statute it is charged with enforcing"); Biogen IDEC MA, Inc. v. Treasurer and Receiver General, 454 Mass. 174, 187 (2009) (finding deference to agency is heightened where interpretation is contemporaneous with enactment of the statute construed); DiCicco v. Dep't of Envtl. Prot., 64 Mass. App. Ct. 423, 427-428 (2005) (agency had discretion to resolve enforcement action with a consent order where statute did not provide a mandatory or definite standard for enforcement actions)).

The Department will evaluate the Companies' request for remuneration pursuant to Section 83D under the framework established in D.P.U. 18-76 through D.P.U. 18-78, as further discussed in our Order on the Attorney General's motion for reconsideration in those cases. See D.P.U. 18-76-A through D.P.U. 18-78-A. As we stated in D.P.U. 18-76 through D.P.U. 18-78, the Companies have the burden to demonstrate that their request for remuneration is reasonable and in the public interest. D.P.U. 18-76 through D.P.U. 18-78, at 72-73.

Section 83 of the Green Communities Act presents a clear policy commitment to the development of clean energy generation resources in Massachusetts. The regulatory framework embedded throughout Section 83 (i.e., Section 83A, Section 83C, and Section 83D) establishes remuneration as a means to compensate the electric distribution companies for accepting the financial obligations of long-term renewable energy contracts. Remuneration plus ratemaking mechanisms addressing the recovery of contract costs ensure that the Companies can maintain strong credit ratings under the financial obligations and risks related to long-term renewable energy contracts. The Companies' strong credit ratings, in turn, support the cost-effective financing mandated by the Green Communities Act (Exh. EDC-RBH-GET-1, at 24).

The Companies have established that (1) regulatory consistency is of critical importance to rating agencies' assessment of a company's credit rating and (2) decisions about remuneration provide the financial markets with important information regarding the commitment to support clean energy generation over the long term (Exhs. JU-1, at 46-53; EDC-RBH-GET-1, at 21-22). As we stated in D.P.U. 18-76 through D.P.U. 18-78, the Department is mindful that establishing a remuneration rate below 2.75 percent could send a negative signal to the financial markets and credit rating agencies regarding regulatory consistency in our review of long-term renewable energy contracts. D.P.U. 18-76 through D.P.U. 18-78, at 69. Altering the existing regulatory framework for remuneration could affect the rating agencies' perception of the stability in the Massachusetts regulatory environment (Exhs. JU-1, at 46-53; EDC-RBH-GET-1, at 21-22). Given the significant obligations under these PPAs and TSAs, this change could negatively impact the Companies' credit ratings and result in increased costs that would ultimately fall to ratepayers (Exhs. JU-1, at 46-53; EDC-RBH-GET-1, at 21, 41-43). This point has particular weight because the Section 83D contracts represent a significant increase in the magnitude of the Companies' financial obligations and there is a greater potential cumulative effect of these long-term obligations on their financial positions[69] (see Exhs. JU-1, at 48-49, 52-53; EDC-RBH-GET-1, at 9, 22, 72-73; DPU 1-7; DPU 3-7; DPU 4-2; DPU 4-4; DPU 4-6; DPU 4-10; Tr. 1, at 80, 131-133).

The Department has reviewed the financial obligation of the Companies under the PPAs and TSAs (Exhs. JU-1, at 46-53; EDC-RBH-GET-1, at 22-27; DPU 4-2; DPU 4-6; DPU 4-10). We have considered the contracts' structure and note that the financial obligation arising from the contracts includes the payments due to HQUS and CMP, which the Companies must pay regardless the design of the cost recovery mechanism (Exhs. EDC-RBH-GET-1, at 9, 24, 25; JU-3-A at § 5.2, § 7.1(c)); JU-3-B at § 5.2, § 7.1(c)); JU-3-C at § 5.2, § 7.1(c)). Therefore, Department finds that the cost recovery

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69 In considering the scale of the relevant obligations, we note that, under the Green Communities Act, the Companies have entered into more than 60 individual contracts for renewable energy with terms of ten to 20 years, including six contracts under Section 83D (Exh. JU-1, at 46). The Companies estimate that their collective financial commitment over the length of these contracts exceeds $22 billion and the cash-flow requirements associated with the contract payments amount to approximately $15 billion, an amount that exceeds any other existing contractual commitment relating to utility operations (Exhs. JU-1, at 46, 47; EDC-RBH-GET-1, at 14, 22, 46-47; DPU 4-6; DPU 2-16-1; Tr. 1, at 109, 114).

mechanism alone does not ameliorate the fact that the Companies bear the contractual obligations, regardless of revenues, cash flow, or access to financial liquidity (Exhs. EDC-RBH-GET-1, at 9, 24, 25; JU-3-A; JU-3-B; JU-3-C at § 5.2, § 7.1(c)).

Based on our review of the financial obligation of the Companies under the long-term contracts and in consideration of the importance of regulatory consistency, as addressed above, the Department finds that the Companies' request for annual remuneration of 2.75 percent of the annual payments under the PPAs and TSAs is reasonable and in the public interest.

In reaching the above determination, the Department has applied its discretion to a number of qualitative factors, as the record lacks sufficient, reliable quantitative analysis to set a remuneration rate.[70] There are a number of potentially relevant considerations for determining financial obligation, including those discussed above. And, contrary to the assertions of the Attorney General and other intervenors, Section 83D does not require the Companies to show a quantified analysis of risk from the PPAs and TSAs in order to qualify for remuneration.[71] Nonetheless, as we have previously stated, the Department expects that

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70 The Companies argue that a quantitative analysis of the net benefits that will accrue to ratepayers under these PPAs supports their proposed remuneration rate (Companies Reply Brief at 72-74). However, as explained below, the Department finds that this analysis is not relevant for determining the financial obligation to an electric distribution company of a long-term contract under Section 83D. D.P.U. 18-76 through D.P.U. 18-78, at 72.

71 More specifically, Section 83D does not require an electric distribution company to demonstrate that it incurs incremental risk associated with entering into a long-term contract to support a certain remuneration rate, nor does it link remuneration to any

the Companies will fully support all future remuneration requests with both quantitative and qualitative analyses that link the requested remuneration level to the specific risks and/or financial burden that the Companies will incur associated with the PPAs and TSAs. D.P.U. 18-76 through D.P.U. 18-78, at 73.

As a method for quantifying the financial obligation incurred by the Companies related to the PPAs and TSAs, the Attorney General again urges the Department to adopt the S&P imputed debt approach (Attorney General Brief at 10-12). However, imputed debt is just one element of a broader credit assessment. D.P.U. 18-76 through D.P.U. 18-78, at 71. In addition, other credit rating agencies have not used this analysis, and S&P has not applied the imputed debt approach to these contracts (Tr. 3, at 450-451; Exhs. AG-VM at 28; EDC-AG-18, Att. 3; EDC-RBH-GET-1, at 39-40). The Department is not persuaded that the S&P imputed debt approach is appropriate to quantify the risk associated with long-term contracts when S&P itself has not done so or indicated that it will do so in the future[72] (Exh. AG 1-1). Accordingly, the Department again declines to adopt the proposed method. D.P.U. 18-76 through D.P.U. 18-78, at 71; See, Tierney v. John Hancock Mut. Life Ins. Co., 58 Mass. App. 571, 583 (2003) quoting Auto. Ins. Bureau of Mass. v. Comm'r of Ins., 430 Mass. 285, 296 (1999) ("In reviewing the commissioner's decision concerning a choice

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specific quantitative analysis that attempts to estimate the financial burden an electric distribution company may incur under a long-term contract.

72 In addition, there is no evidence to support the Attorney General's assertion that, if S&P employed an imputed debt approach, it would estimate a risk factor of close to zero (Tr. 3, at 422). See D.P.U. 18-76 through D.P.U. 18-78, at 71 & n.45; D.P.U. 18-76-A through D.P.U. 18-78-A at 20.

of methodology, we 'give due weight to [her] experience, technical competence, specialized knowledge, and discretionary authority. Deference to the commissioner's expertise and discretion is particularly appropriate when reviewing her choice of methodology.'"); Mass. Coal. for the Homeless v. Sec'y. of Health & Human Servs., 422 Mass. 214, 223 (1996), quoting Williams v. Sec'y. of Exec. Office of Human Servs., 414 Mass. 551, 570 (1993) ("Where the Legislature has not imposed specific restrictions on the reasonable methods by which an agency may carry out its mandate in the plain language of the agency's enabling statute, it is not appropriate for the courts to order the agency to follow specific methods for meeting the agency's mandate.").

The Department recognizes that the Companies' status as credit-worthy contract counterparties has allowed them to enter into highly cost-effective PPAs to facilitate the development of clean energy resources under Section 83D. The Companies cite their quantitative analysis of the net benefits that will accrue to ratepayers under these PPAs as support for the reasonableness of the proposed remuneration rate and suggest that the cost-effectiveness of these contracts could support a much higher level of remuneration (Companies Brief at 54-55; Companies Reply Brief at 72-73). As discussed in Section VII, above, a favorable analysis of net benefits is essential for contract approval. However, the Department did not consider the absolute level of projected net benefits to ratepayers as a factor in determining an appropriate remuneration rate. The level of net benefit to ratepayers is not relevant for determining the financial obligation to an electric distribution company of a long-term contract under Section 83D. D.P.U. 18-76 through D.P.U. 18-78, at 72.

Further, Section 83D does not link the level of remuneration to an estimate of a project's benefits to the Commonwealth or otherwise provide that remuneration is meant to reward the Companies for the level of ratepayer benefits achieved. See D.P.U. 18-76 through D.P.U. 18-78, at 72.

Finally, TEC recommends that the Department adopt an unfixed remuneration rate using a formulaic calculation mechanism that would be subject to change based upon the Companies' actual working capital needs (TEC Reply Brief at 1-3). The record in these cases contains insufficient evidence to support a finding that the financial obligation of the PPAs and TSAs and the related risk to the Companies will change over the contract term. Therefore, based on the record before it, the Department declines to adopt TEC's recommendations.

In conclusion, for the reasons discussed above, the Department finds that the Companies' request for annual remuneration of 2.75 percent of the annual payments under the PPAs and TSAs is reasonable and in the public interest. Our findings here will ensure that (1) the Companies are adequately compensated for accepting the financial obligation of the long-term contracts and (2) ratepayers are not exposed to undue risk from regulatory uncertainty. The Department emphasizes that our findings here do not preclude us from determining that a lower remuneration rate may be appropriate in a future long-term contract proceeding.

Our findings here are intended to provide some guidance regarding the factors the Department will consider in future requests for remuneration. In particular, in future long-term contract proceedings where the level of remuneration is at issue, the Department reiterates its expectation that the Companies will provide both comprehensive qualitative and qualitative analyses[73] to support their remuneration requests. D.P.U. 18-76 through D.P.U. 18-78, at 73. In determining that the record does not support a determination based solely on one of the proposed quantitative methods, we have not rejected a role for quantitative analysis in future cases. We expect that, as the market for clean energy generation resources matures, the potential for relevant quantitative analysis of the burden from accepting the financial obligation of long-term contracts will develop, as well. By requiring that the Companies, in the context of future long-term contract proceedings, provide all available quantitative analyses, the Department seeks to recognize this evolution.[74] Although consideration of a quantitative approach is not possible on the record before us in these cases, a quantitative approach may be appropriate in the future. See D.P.U. 18-76 through D.P.U. 18-78, at 73; D.P.U. 18-76-A through D.P.U. 18-78-A at 24-25.

Finally, we emphasize again that the appropriate level of remuneration is case specific and it is necessary to understand how a long-term contract of a particular size and structure could affect each contracting electric distribution company. Therefore, the Department will

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[73] Such analyses should include both testimony and supporting exhibits.

[74] To the extent that the Companies determine that they are unable to develop relevant, reliable quantitative analyses, they must nonetheless fully document their efforts to do so. The requirement that the Companies provide such quantitative analyses is not a determination that such analysis can or should be relied on by the Department in later cases. In future cases, parties may raise all appropriate arguments regarding the proper use of quantitative analyses to support remuneration requests.

not provide a comprehensive list of all factors we may consider regarding remuneration in a future long-term contract proceeding but will continue to undertake a comprehensive case-by-case analysis as detailed herein.

X. COST RECOVERY

A. Introduction

Subject to review and approval by the Department, an electric distribution company may recover costs incurred under a long-term contract approved pursuant to Section 83D. See Section 83D(i); 220 CMR 24.06(2)(c). Section 83D(h) and the Department's regulations at 220 CMR 24.06(2) provide that a company may, after purchasing energy and RECs[75] (1) use the energy for its basic service load and retain RECs for the purpose of meeting its annual RPS requirements or (2) sell the energy into the wholesale electricity spot market, and sell the RECs to minimize costs to ratepayers, provided that DOER has not notified the company that the RECs should be retained to reach emission reduction targets. If a company chooses to sell the energy and/or RECs, it shall (1) calculate the net cost of payments made under the long-term contracts against the proceeds obtained from the sale of energy and/or RECs and (2) credit or charge all distribution customers the difference between the contract payments and proceeds through a uniform, fully-reconciling annual factor in distribution rates. Section 83D(i); 220 CMR 24.06(2).

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75 As described in Section V.B.2, above, the environmental attributes associated with the hydroelectric generation pertain to CES and GWSA compliance, not RPS compliance. For the purpose of cost recovery under Section 83D, the Department finds that CECs are analogous to RECs.

Each electric distribution company has a Department-approved tariff that addresses the recovery of costs related to the long-term renewable energy contracts and was approved pursuant to Section 83 and Section 83A.[76,77] Under these tariffs, the Companies compare (1) the payments made under the Section 83 and Section 83A contracts plus actual remuneration with (2) the proceeds received from the sale of energy and/or RECs, after netting out the amount either collected from or credited to distribution customers through an LTRCA factor (Exh. JU-1, at 56-67). Any over- or under-recovery is reconciled in the LTRCA applicable in the following year (Exh. JU-1, at 57).

The Companies propose to modify their existing LTRCA tariffs to include recovery of the following costs associated with the long-term contracts procured pursuant to Section 83D: (1) the net costs of the energy sold into the ISO-NE wholesale market; (2) the net costs of any CECs sold; (3) payments under the TSAs; and (4) the remuneration associated with the

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76 The Companies' existing tariffs are as follows: (1) Unitil - M.D.P.U. No. 308; (2) National Grid - M.D.P.U. No. 1304; and (3) Eversource - M.D.P.U. No. 69. The National Grid tariff only addresses the recovery of costs under Section 83A.

77 In D.P.U. 18-76 through D.P.U. 18-78, at 76, the Department approved the Companies' request to recover payments made under the long-term contracts approved pursuant to Section 83C. As part of that Order, the Department directed the Companies uniformly to refer to the cost recovery factor in the applicable tariffs as the "Long-Term Renewable Contract Adjustment" or "LTRCA." D.P.U. 18-76 through D.P.U. 18-78, at 76 n.50.

On May 31, 2019, the Department suspended the compliance tariffs filed by the Companies in D.P.U. 18-76 through D.P.U. 18-78, for further investigation. Long-Term Contracts for Offshore Wind Energy Generation Pursuant to Section 83C, D.P.U. 18-76-B through D.P.U. 18-78-B (May 31, 2019). The Companies' Section 83C compliance tariffs are addressed in Section X.C, below.

annual payments under the PPAs and TSAs (i.e., 2.75 percent) (Exh. JU-1, at 45, 55-57).[78,79] In addition, the Companies seek recovery through the LTRCA of incremental external expenses incurred to carry out the procurement, perform the contract evaluation process, and obtain Department approval of the proposed PPAs and TSAs (Companies Brief at 61-62, 64).

B. Positions of the Parties

In addition to recovery of payments made under the PPAs and TSAs, the Companies request that the Department allow the recovery of incremental expenses incurred to carry out the procurement, perform the contract evaluation process, and obtain Department approval of the proposed PPAs and TSAs (Companies Brief at 61-62). The Companies argue that the solicitation, evaluation, contract negotiation, and regulatory approval process for the PPAs and TSAs is complex, detailed, and time-consuming (Companies Brief at 63). The Companies further maintain that they are required to engage the services of a number of experts and consultants during the RFP preparation, bidder question, and proposal evaluation phase, as well as during contract negotiation and the regulatory approval processes (Companies Brief at 63). The Companies assert that cost recovery is appropriate because the

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[78] The Companies seek approval of the following revised LTRCA tariffs: (1) Unitil - M.D.P.U. No. 317 (proposed); (2) National Grid - M.D.P.U. No. 1361 (proposed); and (3) Eversource - M.D.P.U. No. 69A (proposed).

[79] Consistent with the operation of the current LTRCA tariffs, the Companies propose to calculate the net cost of energy and CECs based on the actual contract prices, projected market prices, and the estimated kWh generated and purchased under the contracts (Exh. JU-1, at 56).

external legal and consulting costs expended for these purposes are generally non-recurring, not recovered in base distribution rates, and not completely offset by the bid fees paid by project sponsors (Companies Brief at 62-63, citing Exh. AG 1-1). No other party addressed this issue on brief.

C. Analysis and Findings

Subject to Department review and approval, the Companies may recover payments made under long-term contracts approved pursuant to Section 83D. See Section 83D(i); 220 CMR 24.06(2)(c). Consistent with Section 83D(g), the Department finds that the Companies have appropriately allocated the contract quantities based on total energy demand from all distribution customers (Exhs. JU-3-A at Exhibit B; JU-3-B at Exhibit B; JU-3-C at Exhibit B; JU-4-A at 17; JU-4-B at 17; JU-4-C at 17). Accordingly, each company's apportioned share of energy and environmental attributes from the PPAs and transmission service from the TSAs is as follows: (1) Eversource - 53.15 percent; (2) National Grid – 45.72 percent; and (3) Unitil - 1.13 percent (Exhs. JU-3-A at Exhibit B; JU-3-B at Exhibit B; JU-3-C at Exhibit B; JU-4-A at 17; JU-4-B at 17; JU-4-C at 17).

The Companies propose to sell the hydroelectric generation procured under the PPAs through the ISO-NE wholesale market and to credit or charge the difference between the wholesale market revenues and the contract costs to each company's distribution customers (Exh. JU-1, at 54-55). In addition, the Companies propose to retain the CECs purchased under the PPAs to fulfill CES requirements associated with their basic service obligations (Exh. JU-1, at 55). If the CES obligation has been met, the Companies propose to sell excess CECs into the market and credit all distribution customers the difference between the PPA price and the sales price (Exh. JU-1, at 20, 53-54).

After review, the Department finds that the Companies' proposed treatment of energy and CECs[80] under the PPAs is consistent with Section 83D and 220 CMR 24.06. Further, the Department finds that the Companies' proposed method to recover net payments made under the PPAs and TSAs is appropriate and consistent with Department precedent. See D.P.U. 18-76 through D.P.U. 18-78, at 75-76; D.P.U. 17-117 through D.P.U. 17-120, at 67.

In addition to net payments made under the PPAs and TSAs, the Companies argue that they should be entitled to recover external legal and consulting costs resulting from the solicitation, evaluation, contract negotiation, and regulatory approval process associated with the PPAs and TSAs, as well as ongoing external costs associated with contract administration ("Procurement and Contract Development Costs") (Companies Brief at 61-62, 64). The Companies made a similar request to recover Procurement and Contract Development Costs as part of the Department's review of long-term contracts for offshore wind energy generation resources under Section 83C in D.P.U. 18-76 through D.P.U. 18-78 (D.P.U. 18-76 through D.P.U. 18-78, Companies Brief at 60-61).

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80 As part of the compliance filing discussed below, each company shall revise its LTRCA formula to include reference to CECs as well as RECs (see Exh. JU-12 (Eversource) at 2.

More specifically, on July 23, 2018, the Companies filed petitions with the Department in D.P.U. 18-76 through D.P.U. 18-78, for approval of long-term contracts to purchase offshore wind energy generation pursuant to Section 83C. The testimony and proposed LTRCA tariffs accompanying those filings did not reference recovery of Section 83C Procurement and Contract Development Costs (see D.P.U. 18-76 through D.P.U. 18-78, Exhs. JU-1; JU-9-A; JU-9-B; JU-9-C). Likewise, the testimony and LTRCA tariffs accompanying the petitions in the instant proceedings did not reference the proposed recovery of Section 83D Procurement and Contract Development Costs (see Exhs. JU-1; JU-12).

On October 18, 2018, in the Section 83C proceeding, the Companies responded to an information request from the Attorney General seeking a description and quantification of the costs associated with the procurement and administration of the RFP and execution of the PPAs in D.P.U. 18-76 through D.P.U. 18-78 (D.P.U. 18-76 through D.P.U. 18-78, Exh. AG 1-1). As part of that response, the Companies proposed for the first time that they be allowed to recover Procurement and Contract Development Costs related to Department-approved contracts under Section 83C (D.P.U. 18-76 through D.P.U. 18-78, Exh. AG 1-1). On November 26, 2018, the Companies responded to an identical information request in the instant proceedings wherein the Companies proposed for the first time that they be allowed to recover Procurement and Contract Development Costs related to Department-approved contracts under Section 83D (Exh. AG 1-1).

On April 12, 2019, the Department issued a final Order in D.P.U. 18-76 through D.P.U. 18-78, approving the PPAs filed pursuant to Section 83C. In that Order, the Department did not address the recovery of Section 83C-related Procurement and Contract Development Costs. See D.P.U. 18-76 through D.P.U. 18-78, at 73-76.

In compliance with D.P.U. 18-76 through D.P.U. 18-78, at 76, the Companies filed revised LTRCA tariffs on April 24, 2019. In addition to Department-required changes addressed in D.P.U. 18-76 through D.P.U. 18-78, at 76, the Companies' LTRCA compliance tariffs included a new Procurement and Contract Development Cost component as part of the LTRCA cost recovery factor.[81] On May 31, 2019, the Department issued an Order suspending the proposed Section 83C LTRCA compliance tariffs for further investigation. D.P.U. 18-76-B through D.P.U. 18-78-B, at 1. As the issue is common to both proceedings, the Department addresses the proposed recovery of Procurement and Contract Development costs for the Section 83C and Section 83D contracts, below.

Because the contracts arise from a legislative policy mandate, the Department finds that it is appropriate to allow the Companies to seek recovery through the LTRCA of incremental external costs incurred to solicit, evaluate, negotiate, execute, and administer

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[81] The proposed revised LTRCA tariffs define Procurement and Contract Development costs as (1) the difference between actual expenditures incurred to solicit, evaluate, negotiate, execute, and obtain regulatory approval of long term renewable energy contracts and fees paid by bidders to participate in the solicitation, excluding internal labor costs, and (2) ongoing external costs of administering long term renewable energy contracts, excluding internal labor costs (D.P.U. 18-76 through D.P.U. 18-78, M.D.P.U. No. 317 (proposed) (Unitil), M.D.P.U. No. 1361 (proposed) (National Grid), M.D.P.U. No. 69B (proposed) (Eversource)).

long term contracts pursuant to Section 83C and Section 83D, which are not covered by the fees paid by bidders or otherwise recovered in rates. As with all costs they seek to recover from ratepayers, the Companies must demonstrate that all Procurement and Contract Development Costs were prudently incurred and reasonable in amount.[82]

Bid fees are used to offset the costs related to the evaluation of proposals and oversight by the Independent Evaluator. D.P.U. 19-45, at 53-54. The Department recently authorized an increase in the minimum bid fee for the second Section 83C solicitation from the previous Section 83C solicitation and, therefore, we expect that future costs incurred to solicit, evaluate, negotiate, execute, and administer long term contracts not covered by the fees paid by bidders will be minimal. D.P.U. 19-45, at 53-54. In this regard, the Companies shall take all reasonable efforts to ensure that the bid fees in any future long-term renewable energy contract solicitation are set at an amount to reflect the estimated costs of evaluating proposals, including the Companies' estimated costs to solicit, evaluate, negotiate, execute, and administer long term contracts. Any over collection of bid fees must be credited to ratepayers through the LTRCA.

At the time cost recovery is sought, the Companies must demonstrate that any Procurement and Contract Development Costs related to Section 83C and Section 83D are

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82 In addition, the Department notes that there are significant differences in the level of estimated procurement and contract development costs identified by the individual companies (D.P.U. 18-76 through D.P.U. 18-78, Exh. AG 1-1, at 2; Exh. AG 1-1, at 2). At the time cost recovery is sought, the Companies must be prepared to fully explain and justify as reasonable and prudent any differences in total spending levels among the individual companies.

incremental and not included as an expense in the test-year used to establish base distribution rates. This is particularly relevant for National Grid as the 2017 test year in the company's pending base distribution rate case appears to include costs incurred to solicit, evaluate, negotiate, execute, and administer long term contracts under Section 83C and/or Section 83D (D.P.U. 18-150, RR-DPU-33 & Att.).

Finally, the Department finds that any request to recover Procurement and Contract Development Costs shall be limited to the costs associated with long term contracts pursuant to Section 83C and Section 83D. Contract administration and other external costs associated with long-term contracts procured pursuant to Section 83 and Section 83A are not eligible for recovery through the LTRCA as the Companies did not seek recovery of such costs in those proceedings.

Subject to the above directives, the Department finds that the Companies' proposed method to recover costs related to the PPAs and TSAs, is consistent with Section 83D and will result in just and reasonable rates pursuant to G.L. c. 164, § 94. See also D.P.U. 18-76 through D.P.U. 18-78, at 76. Accordingly, the Department finds that it is appropriate for the Companies to amend their existing LTRCA tariffs to include the recovery of costs associated with long-term contracts procured pursuant to Section 83C and Section 83D, subject to the directives contained herein. Within 14 days of the date of this Order, each electric distribution company shall file a revised LTRCA tariff for effect September 1, 2019, consistent with the directives contained herein and in D.P.U. 18-76 through D.P.U. 18-78.[83]

As a final matter, the Department notes that the Companies did not raise the issue of recovery of Procurement and Contract Development Costs as part of their Petitions in the Section 83C or Section 83D proceedings.[84] Going forward, the Department expects any cost recovery proposal raised, for the first time, in response to an information request will be accompanied by an appropriate motion to amend the filing (and, where appropriate, a revised exemplar tariff designed implement the proposal).

XI. RECOMMENDATIONS FOR FUTURE SOLICITATIONS

A. Introduction

The Attorney General recommends that the Department require certain changes to the design and evaluation of future long-term renewable energy contract solicitations (Attorney General Brief at 30-31). Specifically, the Attorney General recommends that the Department (1) establish clear rules for prioritizing high-ranking Stage Two projects in Stage Three

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[83] Each company shall file its LTRCA compliance tariff in both the applicable Section 83D docket (i.e., D.P.U. 18-64, D.P.U. 18-65, or D.P.U. 18-66) as well as the applicable Section 83C docket (i.e., D.P.U. 18-76, D.P.U. 18-77, or D.P.U. 18-78).

[84] Recovery of Procurement and Contract Development Costs was also not in the Companies' exemplar LTRCA tariffs filed in D.P.U. 18-64 through D.P.U. 18-66 or D.P.U. 18-76 through D.P.U. 18-78. After raising the request for the first time in each proceeding as part of a response to an information request, the Companies did not seek to amend their filings or file revised exemplar LTRCA tariffs incorporating the request.

portfolio development, (2) direct the Companies to modify the scaling approach used in bid scoring to explicitly consider the relative weighting of qualitative and quantitative factors as opposed to the implicit weighting used in this solicitation, (3) require the Evaluation Team to revise the GWSA metric to directly reflect changes in GHG emissions, (4) separate Selection Team members from Evaluation Team members, and (5) require the Companies to disclose estimated maximum remuneration costs to ratepayers in future long-term renewable energy contracts submitted for Department review (Attorney General Brief at 31).

B. Positions of the Parties

1. Attorney General

The Attorney General argues that her recommendations should be applied to future procurements to incorporate lessons learned in this solicitation (Attorney General Brief at 30).[85] The Attorney General maintains that the size of these procurements renders it crucial that each evaluation process be as robust, nondiscriminatory, and competitive as possible (Attorney General Brief at 30). The Attorney General contends that PPA review proceedings represent a better opportunity than the timetable and method of solicitation proceedings for the Department to issue recommendations regarding faults in the evaluation process and improvements for future bid evaluations (Attorney General Brief at 30). The Attorney General maintains that incorporating lessons learned from the Section 83D process

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85 The Attorney General acknowledges that her recommended changes to the scaling approach used in bid scoring and GWSA metric would not have affected the project rankings resulting in the selection of NECEC Hydro in this solicitation (Exh. AG-DM at 26-27).

to future evaluations of long-term contract bids will help to ensure the best possible results for ratepayers (Attorney General Brief at 31).

2. Companies

The Companies maintain that Section 83D requires the Companies to solicit, and provided reasonable proposals are received, enter into cost-effective long-term contracts for clean energy generation for an annual amount of electricity equal to approximately 9,450,000 MWh (Companies Reply Brief at 40, citing Section 83D(a)). The Companies maintain that, if the Department approves the instant PPAs, the Companies will have fully satisfied their obligations under Section 83D (Companies Reply Brief at 40). Therefore, the Companies argue that it would be premature to require changes in a yet undefined contract evaluation (Companies Reply Brief at 40).

3. Department of Energy Resources

While DOER concurs with the Attorney General that there are lessons to be learned after any bid evaluation process, DOER maintains that it is appropriate to consider changes to the process if, and when, there is legislative authorization for another solicitation under Section 83D (DOER Reply Brief at 17). At that time, DOER contends that the Companies, DOER, and the Attorney General can consider process improvements during the collaborative RFP drafting process (DOER Reply Brief at 17). In this regard, DOER maintains that Section 83C and Section 83D require the timetable and method of solicitation to be jointly developed by DOER and the Companies, in consultation with the Attorney General and with oversight by an Independent Evaluator (DOER Reply Brief at 17-18). DOER asserts that the

RFP drafting process benefits from robust discussions among the participating parties (DOER Reply Brief at 18). Accordingly, DOER maintains that the Attorney General's recommendations are most appropriately considered during the RFP drafting process and not within the instant contract review proceedings (DOER Reply Brief at 18).

C. Discussion

The Department recently addressed the Attorney General's argument that the Companies should disclose the costs associated with remuneration in future long-term contract review proceedings in the timetable and method of solicitation for the second solicitation of long-term contracts for offshore wind energy pursuant to Section 83C. D.P.U. 19-45, at 69. In order to eliminate any inconsistencies with regard to remuneration in the Companies' analyses of contract costs in future contract review proceedings, the Department directed the Companies to include remuneration costs in all analyses that relate to contract costs or cost effectiveness. D.P.U. 17-117 through D.P.U. 17-120, at 63. As this finding applies broadly to all future long-term renewable energy contract proceedings, the Department need not make any additional findings here.

Our discussion of the disclosure of remuneration costs notwithstanding, the Department has determined that a contract review proceeding is typically not the best forum to address the design and implementation of future RFPs. See e.g., D.P.U. 18-76 through D.P.U. 18-78, at 88; D.P.U. 17-117 through D.P.U. 17-120, at 72-74. Instead, we find that the RFP drafting process or other non-adjudicatory proceeding is a more appropriate forum to consider process improvements, as it allows for significant stakeholder input.

D.P.U. 18-76 through D.P.U. 18-78, at 88. For these reasons, the Department will not address any recommendations for future long-term solicitations in this Order. Nonetheless, the Department acknowledges the importance of stakeholder involvement in considering improvements to the solicitation and evaluation of future long-term contracts for renewable energy and fully expects that the Companies and DOER will fully engage the Attorney General and other participating stakeholders in a robust, collaborative RFP drafting process that benefits from lessons learned in the instant solicitation.

XII. ORDER

Accordingly, after notice, hearing and due consideration, it is:

ORDERED: That the power purchase agreement between NSTAR Electric Company, d/b/a Eversource Energy and H.Q. Energy Services (U.S.) Inc. for hydroelectric generation and associated environmental attributes filed on July 23, 2018, pursuant to St. 2008, c. 169, § 83D and 220 CMR 24.00, is APPROVED; and it is

FURTHER ORDERED: That the power purchase agreement between Massachusetts Electric Company and Nantucket Electric Company, d/b/a National Grid and H.Q. Energy Services (U.S.) Inc. for hydroelectric generation and associated environmental attributes filed on July 23, 2018, pursuant to St. 2008, c. 169, § 83D and 220 CMR 24.00, is APPROVED; and it is

FURTHER ORDERED: That the power purchase agreement between Fitchburg Gas and Electric Light Company, d/b/a Unitil and H.Q. Energy Services (U.S.) Inc. for hydroelectric generation and associated environmental attributes filed on July 23, 2018, pursuant to St. 2008, c. 169, § 83D and 220 CMR 24.00, is APPROVED; and it is

FURTHER ORDERED: That NSTAR Electric Company, d/b/a Eversource Energy, Massachusetts Electric Company and Nantucket Electric Company, d/b/a National Grid, and Fitchburg Gas and Electric Light Company, d/b/a Unitil shall comply with all other directives contained in the Order.

By Order of the Department,

/s/
Matthew H. Nelson, Chair

/s/
Robert E. Hayden, Commissioner

/s/
Cecile M. Fraser, Commissioner

An appeal as to matters of law from any final decision, Order or ruling of the Commission may be taken to the Supreme Judicial Court by an aggrieved party in interest by the filing of a written petition praying that the Order of the Commission be modified or set aside in whole or in part. Such petition for appeal shall be filed with the Secretary of the Commission within twenty days after the date of service of the decision, order or ruling of the Commission, or within such further time as the Commission may allow upon request filed prior to the expiration of the twenty days after the date of service of said decision, order or ruling. Within ten days after such petition has been filed, the appealing party shall enter the appeal in the Supreme Judicial Court sitting in Suffolk County by filing a copy thereof with the Clerk of said Court. G.L. c. 25, § 5.