FINAL AGENDA
NEPOOL Participants Committee
Working Session: Pathways to the Future Grid
April 15, 2021, 9:30 a.m. – 3:30 p.m.

To participate in the special Participants Committee Teleconference,
please dial 1-866-803-2146; Passcode 7169224.
To join the WebEx, click this link and enter the event password **nepool**.

The final list of agenda items for the April 15 working session are as follows:

1. To approve the draft minutes of the February 18, 2021 and March 18, 2021 Participants Committee "Pathways Study" meetings. The draft preliminary minutes of those meetings are included with this supplemental notice and posted with the meeting materials.

2. Presentation & continued discussion to help scope and define the ISO's pathways analyses, including:
   - Discussions to further develop any outstanding elements within the study scope of the FCEM and net carbon pricing frameworks;
   - ISO's response to feedback; and
   - Kickoff of modeling discussions on the planned studies.

PRELIMINARY

Pursuant to notice duly given, a meeting of the NEPOOL Participants Committee was held via teleconference beginning at 9:30 a.m. on Thursday, February 18, 2021. Attachment 1 identifies the members, alternates and temporary alternates who participated in the teleconference meeting.

Mr. David Cavanaugh, Chair, presided and Mr. Sebastian Lombardi, Assistant Secretary, recorded. Mr. Cavanaugh welcomed everyone to the kick-off of the Pathways to the Future Grid evaluation process. He explained that the intended goal of this process was to help the ISO scope and define its proposed deeper analysis of two potential pathways, net carbon pricing and a forward clean energy market (FCEM), with additional consideration about the joint optimization process and resource adequacy. At this first meeting, the ISO would review the intended scope of its evaluation to help identify key elements for effective modeling. At future meetings, stakeholders would have the chance to discuss additional design elements for the ISO to consider. He noted that those future meetings had tentatively been scheduled for Thursday, March 18, Thursday April 15, Thursday May 13, and Friday, June 11.

Chadalavada Presentation

Dr. Vamsi Chadalavada, ISO Executive Vice President and Chief Operating Officer, began the ISO presentation, referring to materials that had been circulated and posted in advance of the meeting. He highlighted that the study time horizons for the various ongoing and planned Future Grid-related studies would span 2030 to 2050. He explained that the time period required for conducting these studies/analyses would encompass the remainder of the year with results from Phase 1 of NEPOOL's Future Grid Reliability Study expected to be completed in the first quarter of 2022. He then proceeded through the presentation, sequentially reviewing the various studies planned and the ISO's reasons for its proposed sequencing and involvement of stakeholders.

During his review of the presentation, Dr. Chadalavada responded to comments and questions. He noted the importance of defining balancing resources in the context of the various ancillary services needed in the future. He acknowledged the immediate need to address the Minimum Offer Price Rule (MOPR), to build out effective load carrying capability (ELCC) for various technologies in order to improve the calculation of future capacity needs, and to ensure currency in understanding evolving technology such as evolutions with inverter technology. Dr. Chadalavada flagged the importance of maintaining reliability during the region's transition to the future grid, anticipating the possibility of disorderly retirements in light of how MOPR is addressed, noting that interim changes might be needed to the markets if reliability concerns are identified by the studies. He agreed that the ISO would need to stay focused on ramping capability as the resource mix changes with additional intermittent resources on the grid. He explained that stakeholder input would be sought through the Planning Advisory Committee (PAC) in defining the future transmission topology for the various studies and scenarios.

Geissler Introductory Presentation

Following Dr. Chadalavada's remarks, Dr. Chris Geissler from the ISO reviewed his presentation that was circulated in advance of the meeting entitled "Evaluating clean energy and carbon pricing frameworks as alternative market designs to advance the region's clean energy transition." He highlighted the ISO's specific request for stakeholder feedback on the following: (i) what study year(s) should be evaluated; (ii) what are the regional and state carbon emissions targets for the study year(s); (iii) what are the assumed load levels and shapes; and (iv) what are the assumptions regarding the MOPR. He reviewed the anticipated stakeholder schedule and opportunities for stakeholder input and feedback through the first three quarters of 2021.

In response to questions and comments, Dr. Geissler noted the importance of the States' engagement in finding a market-based solution to the current challenges imposed by MOPR. The ISO was still working to define the model(s) that will be used for their Pathways analysis, with the intent to produce both quantitative and qualitative outcomes, considering the impact on the markets and consumers. He agreed that the modeling needed to reflect that some but not all resources will have Power Purchase Agreements (PPAs), as well as many other factors that impact design. The ISO planned to identify those study factors that will have the biggest impact on actual modeling outcomes and feasibility. He agreed those factors needed to consider whether the procurement of clean energy through a FCEM would be separate or accomplished instead through in a single forward capacity auction each year. Further, the modeling would need to account for the objectives of the states in the region deciding how their loads are to be served. The model would be adjusted as needed to account for changes to or replacement of MOPR and Offer Review Trigger Prices (ORTPs).

Concluding the process discussion, Mr. Geissler noted that the ISO would work to reflect stakeholder feedback into the models developed; the ISO's ability to accommodate that feedback, however, would depend on the degree of stakeholder consensus, feasibility and time constraints.

Fuller Presentation

Next, Mr. Peter Fuller, and Mr. David O'Connor of ML Strategies, on behalf of NRG, provided an overview of the necessary and desirable characteristics of a potential FCEM for New England. Mr. Fuller reviewed the process undertaken with other regional stakeholders that helped to inform the contents of the December 2020 paper summarizing potential FCEM framework parameters, which had been circulated and posted in advance of the meeting. Then Mr. Fuller reviewed the objectives of FCEM, generally and specifically as outlined in an accompanying presentation, also circulated in advance of the meeting. He reviewed the alternative market and regulatory integration approaches contained in the presentation, emphasizing that clean energy attributes would be tradable separate from energy, with the ISO settling the market annually much as the renewable energy credit market is currently settled. He completed his remarks by reviewing critical open questions listed in the presentation.

Following his presentation, Mr. Fuller responded to numerous questions and comments. He clarified that, while the FCEM design parameters paper was the product of extensive outreach with the ISO, states and Market Participants, it could not be represented to be a consensus position of all involved. He encouraged any stakeholder that wished to to join the FCEM working group. Mr. Fuller noted for modeling purposes the importance of starting with a simple product definition. He acknowledged the need for FCEM proponents to demonstrate the importance of the model to the states and how it fits into a well-functioning market.

Geissler Presentation on Modeling Plans for FCEM and Net Carbon Pricing

Dr. Geissler followed Mr. Fuller's presentation with a review of the remaining 11 slides of the ISO's presentation, beginning with the ISO's plans for modeling a FCEM. More specifically, he flagged the numerous key design questions outlined in the presentation that needed to be answered before the model could be constructed. He noted for a potential design that would jointly optimize forward capacity and "clean energy" positions (referred to as the Integrated Clean Capacity Market (ICCM) framework) the ISO would rely on the presentation provided to NEPOOL by Ms. Kathleen Spees in October 2020, but questions still remained.

Before proceeding to talk about the proposed modeling for net carbon pricing, Dr. Geissler received and responded to a number of questions and comments concerning FCEM. He noted that much work was needed to define the study parameters and it was suggested that the ISO could help that effort by presenting its views of the tradeoffs associated with the various options. He indicated that the ISO would be concerned with market power and efficiency if renewable energy credits were split into multiple sub-attributes.

Dr. Geissler then reviewed the slides from the presentation concerning the ISO's net carbon pricing framework, which he characterized as having far fewer questions to be resolved in order to be modelled. He reviewed the questions in the presentation that were yet to be addressed and encouraged stakeholder input on suggested responses.

Dr. Geissler concluded his presentation noting that the ISO would evaluate market outcomes under the FCEM and the net carbon pricing frameworks with the assistance of stakeholders and the Analysis Group. He noted that stakeholder feedback was welcome on the model assumptions and outstanding questions related to these frameworks to facilitate modeling efforts. The final report on modeled market outcomes associated with these frameworks would be shared in February 2022. He noted in response to concluding questions that the ISO intended the net carbon pricing model to rebate revenues back to load. He acknowledged the modeling would need to account for the varying impacts net carbon pricing could have on both marginal and infra-marginal resources.

Mr. Cavanaugh concluded the meeting by noting that the next working session would take place on March 18th, urging interested persons to e-mail written feedback or comments to Dr. Geissler and himself.

There being no further business, the meeting adjourned shortly after 3:00 p.m.

Respectfully submitted,

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Sebastian Lombardi, Assistant Secretary

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES PARTICIPATING IN FEBRUARY 18, 2021 TELECONFERENCE MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Acadia Center	End User	Deborah Donovan		
Advanced Energy Economy	Fuels Industry Participant	Caitlin Marquis		
AR Large Renewable Generation (RG) Group Member	AR-RG	Alex Worsley		
AR Small Load Response (LR) Group Member	AR-LR	Brad Swalwell		
AR Small RG Group Member	AR-RG	Erik Abend		
Ashburnham Municipal Light Plant	Publicly Owned Entity		Brian Thomson	
AVANGRID: CMP/UI	Transmission		Alan Trotta	
Belmont Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Block Island Utility District	Publicly Owned Entity	Dave Cavanaugh		
Borrego Solar Systems Inc.	AR-DG	Liz Delaney		
Boylston Municipal Light Department	Publicly Owned Entity		Brian Thomson	
BP Energy Company	Supplier			José Rotger
Braintree Electric Light Department	Publicly Owned Entity			Dave Cavanaugh
Brookfield Renewable Trading and Marketing	Supplier	Aleks Mitreski		
Calpine Energy Services, LP	Supplier	Brett Kruse		Bill Fowler
Castleton Commodities Merchant Trading	Supplier			Bob Stein
Central Rivers Power	AR-RG		Dan Allegretti	Mike Booth
Chester Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Chicopee Municipal Lighting Plant	Publicly Owned Entity		Brian Thomson	
CLEAResult Consulting, Inc.	AR-DG	Tamera Oldfield		
Clearway Power Marketing LLC	Supplier			Pete Fuller
Concord Municipal Light Plant	Publicly Owned Entity		Dave Cavanaugh	
Connecticut Municipal Electric Energy Coop.	Publicly Owned Entity	Brian Forshaw		
Conservation Law Foundation (CLF)	End User	Phelps Turner		
Consolidated Edison Energy, Inc.	Supplier	Norman Mah		
CPV Towantic, LLC	Generation	Joel Gordon		
Cross-Sound Cable Company (CSC)	Supplier		José Rotger	
Danvers Electric Division	Publicly Owned Entity		Dave Cavanaugh	
Deepwater Wind Block Island, LLC	Generation	Eric Wilkerson		
Dominion Energy Generation Marketing, Inc.	Generation		Weezie Nuara	
DTE Energy Trading, Inc.	Supplier			José Rotger
Dynegy Marketing and Trade, LLC	Supplier	Andy Weinstein		Bill Fowler
Emera Energy Services	Supplier			Bill Fowler
Enel X North America, Inc.	AR-LR	Michael Macrae		
ENGIE Energy Marketing NA, Inc.	AR-RG	Sarah Bresolin		
Environmental Defense Fund	End User	Jolette Westbrook		
Eversource Energy	Transmission	James Daly	Dave Burnham	Jason Stark; Parker Littlehale
Excelerate Energy LP	Fuels Industry Participant	Gary Ritter		
Exelon Generation Company	Supplier	Steve Kirk	Bill Fowler	
FirstLight Power Management, LLC	Generation	Tom Kaslow		
Galt Power, Inc.	Supplier	José Rotger		
Generation Group Member	Generation		Abby Krich	
Georgetown Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Great River Hydro	AR-RG	Shawn Keniston		Bill Fowler
Groton Electric Light Department	Publicly Owned Entity		Brian Thomson	
Groveland Electric Light Department	Publicly Owned Entity		Dave Cavanaugh	
H.Q. Energy Services (U.S.) Inc. (HQUS)	Supplier	Louis Guilbault	Bob Stein	
High Liner Foods (USA) Incorporated	End User		William P. Short III	

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES PARTICIPATING IN FEBRUARY 18, 2021 MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Hingham Municipal Lighting Plant	Publicly Owned Entity	John Coyle	Dave Cavanaugh	
Holden Municipal Light Department	Publicly Owned Entity		Brian Thomson	
Holyoke Gas & Electric Department	Publicly Owned Entity		Brian Thomson	
Hull Municipal Lighting Plant	Publicly Owned Entity		Brian Thomson	
Ipswich Municipal Light Department	Publicly Owned Entity		Brian Thomson	
Jericho Power LLC (Jericho)	AR-RG	Mark Spencer	Nancy Chafetz	Herb Healy; Marji Philips
Littleton (MA) Electric Light and Water Department	Publicly Owned Entity		Dave Cavanaugh	
Littleton (NH) Water & Light Department	Publicly Owned Entity		Craig Kieny	
Long Island Power Authority (LIPA)	Supplier		Bill Killgoar	
Maine Public Advocate’s Office	End User	Drew Landry		
Mansfield Municipal Electric Department	Publicly Owned Entity		Brian Thomson	
Maple Energy LLC	AR-LR			Doug Hurley
Marble River, LLC	Supplier		John Brodbeck	
Marblehead Municipal Light Department	Publicly Owned Entity		Brian Thomson	
Mass. Attorney General’s Office (MA AG)	End User	Tina Belew	Ben Griffiths	Tim Reppucci
Mass. Bay Transportation Authority	Publicly Owned Entity		Dave Cavanaugh	
Mass. Municipal Wholesale Electric Company	Publicly Owned Entity	Brian Thomson		
Mercuria Energy America, LLC	Supplier			José Rotger
Merrimac Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Michael Kuser	End User		Jason York	
Middleborough Gas & Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Middleton Municipal Electric Department	Publicly Owned Entity		Dave Cavanaugh	
National Grid	Transmission		Tim Martin	
Natural Resources Defense Council	End User	Bruce Ho		
Nautilus Power, LLC	Generation		Bill Fowler	
New Hampshire Electric Cooperative	Publicly Owned Entity	Steve Kaminski		Brian. Forshaw; Dave Cavanaugh; Brian Thomson
New Hampshire Office of Consumer Advocate (NHOCA)	End User	Pradip Chattopadhyay		
NextEra Energy Resources, LLC	Generation	Michelle Gardner		
North Attleborough Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Norwood Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
NRG Power Marketing LLC	Generation		Pete Fuller	
Pascoag Utility District	Publicly Owned Entity		Dave Cavanaugh	
Paxton Municipal Light Department	Publicly Owned Entity		Brian Thomson	
Peabody Municipal Light Department	Publicly Owned Entity		Brian Thomson	
Princeton Municipal Light Department	Publicly Owned Entity		Brian Thomson	
PSEG Energy Resources & Trade LLC	Supplier		Eric Stallings	
Reading Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Rodan Energy Solutions (USA) Inc.	Provisional Member	Aaron Breidenbaugh		
Rowley Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Russell Municipal Light Dept.	Publicly Owned Entity		Brian Thomson	
Shrewsbury Electric & Cable Operations	Publicly Owned Entity		Brian Thomson	
South Hadley Electric Light Department	Publicly Owned Entity		Brian Thomson	
Sterling Municipal Electric Light Department	Publicly Owned Entity		Brian Thomson	
Stowe Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Sunrun Inc.	AR-DG			Pete Fuller
Taunton Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Templeton Municipal Lighting Plant	Publicly Owned Entity		Brian Thomson	
The Energy Consortium	End User		Mary Smith	

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES PARTICIPATING IN FEBRUARY 18, 2021 MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Union of Concerned Scientists	End User	Mike Jacobs	Francis Pullaro	
Vermont Electric Cooperative	Publicly Owned Entity	Craig Kieny		
Vermont Electric Power Co. (VELCO)	Transmission	Frank Ettori		
Vermont Energy Investment Corp (VEIC)	AR-LR		Doug Hurley	
Vermont Public Power Supply Authority	Publicly Owned Entity			Brian Forshaw
Versant Power	Transmission	Lisa Martin		
Village of Hyde Park (VT) Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Vitol Inc.	Supplier	Joe Wadsworth		
Wakefield Municipal Gas & Light Department	Publicly Owned Entity		Brian Thomson	
Wallingford DPU Electric Division	Publicly Owned Entity		Dave Cavanaugh	
Wellesley Municipal Light Plant	Publicly Owned Entity		Dave Cavanaugh	
West Boylston Municipal Lighting Plant	Publicly Owned Entity		Brian Thomson	
Westfield Gas & Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Wheelabrator North Andover Inc.	AR-RG		Bill Fowler	

PRELIMINARY

Pursuant to notice duly given, a meeting of the NEPOOL Participants Committee was held via teleconference beginning at 9:30 a.m. on Thursday, March 18, 2021. Attachment 1 identifies the members, alternates and temporary alternates who participated in the teleconference meeting.

Mr. David Cavanaugh, Chair, presided and Mr. Sebastian Lombardi, Acting Secretary, recorded. Mr. Cavanaugh welcomed everyone to the second meeting of Pathways to the Future Grid evaluation process. He provided an overview of the agenda. He thanked those who provided written comments following the February 18 meeting.

ISO Presentation

On behalf of the ISO, Dr. Chris Geissler reviewed materials that had been circulated and posted in advance of the meeting that discussed the ISO's plans for evaluating, by early in 2022, a forward clean energy market construct and a net carbon pricing framework. He reviewed the slides summarizing stakeholder comments on each of the pathways and the ISO's planned responses.

Forward Clean Energy Market (FCEM)

Beginning with the FCEM construct, he reviewed slides covering planned assumptions concerning market design, settlements, and three alternative approaches to address the interaction between clean energy certificates (CECs) under FCEM and existing state renewable energy certificate (RECs) programs (separate attributes tracked by CECs and RECs; CECs account for all environmental attributes for resources that receive them, with RECs received only by resources that do not receive CECs; and FCEM replaces all existing REC programs). In response to questions during his presentation, Dr. Geisler confirmed that the ISO's evaluation would include a base case with existing Market Rules that achieves the states' decarbonization goals, however implemented. He acknowledged the need to define in detail how energy storage might be treated in both the FCEM and net carbon pricing frameworks. He committed to further analyze the implications of assuming a static value for clean energy certificates versus dynamic values that vary up and down depending on the intensity of the emissions. On this same topic, it was noted that the dynamic attribute credit issue ties directly into the carbon accounting issue. Dr. Geissler highlighted for the Committee the ISO's current view that evaluating dynamic certificates instead of static values would be far more complicated to design and model. He noted that the role of offshore wind would be explored further throughout the ISO's evaluation.

Further responding to questions and comments during his presentation, Dr. Geissler acknowledged the importance of assessing how each type of resource might fare under FCEM. He agreed that demand for CECs would certainly be affected by how RECs would be treated. He indicated that the study would seek to provide comparative data across the various approaches, acknowledging that outcomes could vary depending on assumptions made about the continuation of the REC program(s). He opined that he did not expect any modeling scenario to assume separate compensation through RECs and CECs for the very same attributes, noting however the need for further review of this issue in designing the study.

Integrated Clean Capacity Market (ICCM)

Dr. Geissler proceeded to review the portion of the presentation regarding an ICCM and how that framework would integrate with the Forward Capacity Market (FCM). Under ICCM resources would submit a single offer for two products: capacity and clean energy. A single auction would be conducted and produce integrated prices for capacity and clean energy, with the auction designed to acquire the most capacity and clean energy possible at the lowest combined prices for those two products. He explained that many details remained to be worked out with this framework, which would be more complex than FCEM because of the need for integrating the capacity and clean energy markets. He reviewed the design concept, referencing written materials previously circulated, and then turned to Mr. Steven Otto, who reviewed slides that provided a numerical example and key observations of the potential ICCM construct, which included supply and demand parameters, clearing and awards, determination of prices, and resource compensation. He explained that the numerical example presumed that offers were fully rationable (meaning the auction could award a resource forward positions for less than that resource's maximum capacity capability). He concluded explaining that, because resources would receive two prices in the auction, one for capacity and one for clean energy, resources would receive different payment rates per MW of capacity sold, based on their quantity of clean energy that clears in the auction.

Following the presentation on ICCM, some members commented that the market design should include some degree of non-rationable offers (where a resource's award would be all-or-nothing). Commenters agreed that ICCM and FCM needed to be considered in an integrated matter. The ISO encouraged stakeholders to provide as much additional feedback as possible on this potential framework, noting that, at present, the ISO has not evaluated the implementation challenges that may arise when considering whether the ICCM framework could be sensibly translated into a more fully developed market design.

Net Carbon Pricing

Dr. Geissler continued the presentation by reviewing the straw net carbon pricing framework module, referring to additional material included within an ISO memo circulated with the meeting materials, that provided additional detail on this framework. Those materials defined the product in the market as carbon emissions, with either the price or the quantities in the market fixed. He explained that suppliers would be charged to emit and collections from those charges would be redistributed to load. He noted that, like FCEM, a decision had to be made about whether existing REC programs continue or are replaced by this new framework.

Dr. Geissler concluded his presentation noting that the ISO will evaluate market outcomes under the FCEM and the net carbon pricing frameworks with the assistance of stakeholders and the Analysis Group. Plans called for the final report on modeled market outcomes associated with these frameworks to be shared with stakeholders in February 2022. He noted that the ISO was in the preliminary stages of determining modeling constraints and mechanical implementation, with modeling to reflect both price and quantity caps. He explained that the ISO is proposing for stakeholder consideration that the revenue collected from a net carbon price would be rebated to all Real-Time Load Obligation (RTLO) in New England, and would not vary between states. He did note, though, that payments by resources would be in direct proportion to the intensity of their carbon emissions. Further, he indicated that the ISO is still working to define how imports and exports would be handled under this framework. He indicated that it was not necessary for near-term modeling to choose between a carbon tax versus a cap-and-trade design, but that the design differences could matter later in the study process.

In discussions, Dr. Geissler acknowledged that more information needed to be assembled to identify the extent to which the net carbon pricing framework would help to meet state goals and initiatives. He said, further, that the ISO had not yet determined whether or how the Regional Greenhouse Gas Initiative (RGGI) might be included in the model.

Mr. Cavanaugh ended the meeting by noting that the next working session was scheduled for April 15. He urged that written comments be e-mailed to him and Dr. Geissler on or before March 29.

There being no further business, the meeting adjourned at 2:40 p.m.

Respectfully submitted,

Sebastian Lombardi, Acting Secretary

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN MARCH 18, 2021 TELECONFERENCE MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Advanced Energy Economy	Fuels Industry Participant	Caitlin Marquis		
American Petroleum Institute	Fuels Industry Participant	Paul Powers		
AR Large Renewable Generation (RG) Group Member	AR-RG	Alex Worsley		
AR Small Distributed Generation (DG) Group Member	AR-DG	Any Karetsky		
AR Small Load Response (LR) Group Member	AR-LR	Brad Swalwell		
AR Small RG Group Member	AR-RG	Erik Abend		
Ashburnham Municipal Light Plant	Publicly Owned Entity		Brian Thomson	
Associated Industries of Massachusetts (AIM)	End User			Roger Borghesani
AVANGRID: CMP/UI	Transmission		Alan Trotta	
Belmont Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Block Island Utility District	Publicly Owned Entity	Dave Cavanaugh		
Borrego Solar Systems Inc.	AR-DG	Liz Delaney		
Boylston Municipal Light Department	Publicly Owned Entity		Brian Thomson	
BP Energy Company	Supplier			José Rotger
Braintree Electric Light Department	Publicly Owned Entity			Dave Cavanaugh
Brookfield Renewable Trading and Marketing	Supplier	Aleks Mitreski		
Calpine Energy Services, LP	Supplier	Brett Kruse		Bill Fowler
Castleton Commodities Merchant Trading	Supplier			Bob Stein
Central Rivers Power	AR-RG		Dan Allegretti	
Chester Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Chicopee Municipal Lighting Plant	Publicly Owned Entity		Brian Thomson	
CLEAResult Consulting, Inc.	AR-DG	Tamera Oldfield		
Concord Municipal Light Plant	Publicly Owned Entity		Dave Cavanaugh	
Connecticut Municipal Electric Energy Coop.	Publicly Owned Entity	Brian Forshaw		
Conservation Law Foundation (CLF)	End User	Phelps Turner		
Consolidated Edison Energy, Inc.	Supplier	Norman Mah		
CPV Towantic, LLC	Generation	Joel Gordon		
Cross-Sound Cable Company (CSC)	Supplier		José Rotger	
Danvers Electric Division	Publicly Owned Entity		Dave Cavanaugh	
Dominion Energy Generation Marketing, Inc.	Generation		Weezie Nuara	
DTE Energy Trading, Inc.	Supplier			José Rotger
Dynegy Marketing and Trade, LLC	Supplier	Andy Weinstein		Bill Fowler
Emera Energy Services	Supplier			Bill Fowler
Enel X North America, Inc.	AR-LR	Michael Macrae		
Environmental Defense Fund	End User	Jolette Westbrook		
Eversource Energy	Transmission	James Daly		Parker Littlehale; Jason Stark
Exelon Generation Company	Supplier	Steve Kirk	Bill Fowler	
FirstLight Power Management, LLC	Generation	Tom Kaslow		
Galt Power, Inc.	Supplier	José Rotger		
Generation Group Member	Generation	Dennis Duffy	Abby Krich	Alex Worsley
Georgetown Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Great River Hydro	AR-RG			Bill Fowler
Groton Electric Light Department	Publicly Owned Entity		Brian Thomson	
Groveland Electric Light Department	Publicly Owned Entity		Dave Cavanaugh	
H.Q. Energy Services (U.S.) Inc. (HQUS)	Supplier	Louis Guilbault	Bob Stein	
High Liner Foods (USA) Incorporated	End User		William P. Short III	
Hingham Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Holden Municipal Light Department	Publicly Owned Entity		Brian Thomson	

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES PARTICIPATING IN MARCH 18, 2021 TELECONFERENCE MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Holyoke Gas & Electric Department	Publicly Owned Entity		Brian Thomson	
Hull Municipal Lighting Plant	Publicly Owned Entity		Brian Thomson	
Ipswich Municipal Light Department	Publicly Owned Entity		Brian Thomson	
Jericho Power LLC (Jericho)	AR-RG	Mark Spencer	Nancy Chafetz	Marji Philips
Littleton (MA) Electric Light and Water Department	Publicly Owned Entity		Dave Cavanaugh	
Long Island Power Authority (LIPA)	Supplier		Bill Killgoar	
Maine Power	Supplier	Jeff Jones		
Mansfield Municipal Electric Department	Publicly Owned Entity		Brian Thomson	
Maple Energy LLC	AR-LR			Doug Hurley
Marble River, LLC	Supplier		John Brodbeck	
Marblehead Municipal Light Department	Publicly Owned Entity		Brian Thomson	
Mass. Attorney General's Office (MA AG)	End User	Tina Belew	Ben Griffiths	
Mass. Bay Transportation Authority	Publicly Owned Entity		Dave Cavanaugh	
Mass. Municipal Wholesale Electric Company	Publicly Owned Entity	Brian Thomson		
Mercuria Energy America, LLC	Supplier			José Rotger
Merrimac Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Michael Kuser	End User		Jason York	
Middleborough Gas & Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Middleton Municipal Electric Department	Publicly Owned Entity		Dave Cavanaugh	
National Grid	Transmission	Tim Brennan	Tim Martin	
Natural Resources Defense Council	End User	Bruce Ho		
Nautilus Power, LLC	Generation		Bill Fowler	
New Hampshire Electric Cooperative	Publicly Owned Entity	Steve Kaminski		Brian. Forshaw; Dave Cavanaugh; Brian Thomson
New Hampshire Office of Consumer Advocate (NHOCA)	End User			Jason Frost
North Attleborough Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Norwood Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
NRG Power Marketing LLC	Generation		Pete Fuller	
Pascoag Utility District	Publicly Owned Entity		Dave Cavanaugh	
Paxton Municipal Light Department	Publicly Owned Entity		Brian Thomson	
Peabody Municipal Light Department	Publicly Owned Entity		Brian Thomson	
PowerOptions, Inc.	End User			Jason Frost
Princeton Municipal Light Department	Publicly Owned Entity		Brian Thomson	
PSEG Energy Resources & Trade LLC	Supplier		Eric Stallings	
Reading Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Repsol Energy North America	Fuels Industry Participant		Karen Iampen	
Rodan Energy Solutions (USA) Inc.	Provisional	Aaron Breidenbaugh		
Rowley Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Russell Municipal Light Dept.	Publicly Owned Entity		Brian Thomson	
Shrewsbury Electric & Cable Operations	Publicly Owned Entity		Brian Thomson	
South Hadley Electric Light Department	Publicly Owned Entity		Brian Thomson	
Sterling Municipal Electric Light Department	Publicly Owned Entity		Brian Thomson	
Stowe Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Sunrun Inc.	AR-DG			Pete Fuller
Taunton Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Templeton Municipal Lighting Plant	Publicly Owned Entity		Brian Thomson	
The Energy Consortium	End User	Roger Borghesani	Mary Smith	Joyceline Chow
Vermont Electric Power Company (VELCO)	Transmission	Frank Ettori		
Vermont Energy Investment Corp (VEIC)	AR-LR		Doug Hurley	

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PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
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Versant Power	Transmission	Lisa Martin		
Village of Hyde Park (VT) Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Wakefield Municipal Gas & Light Department	Publicly Owned Entity		Brian Thomson	
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Westfield Gas & Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Wheelabrator North Andover Inc.	AR-RG		Bill Fowler	

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APRIL 15, 2021 | NEPOOL PARTICIPANTS COMMITTEE WORKING SESSION

Pathways to the Future Grid

Evaluating clean energy and carbon pricing frameworks as alternative market approaches to advance the region's clean energy transition

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Pathways work will evaluate two potential market approaches to decarbonization

- ISO is working with stakeholders and the Analysis Group to evaluate two market approaches that have been discussed as potential pathways to the future grid
  - Forward clean energy market (FCEM)
  - Net carbon pricing
- ISO plans to study both frameworks simultaneously and issue a final report in the first quarter of 2022 that discusses the market impacts of both approaches
- Today's discussion will not focus on sequential versus integrated clearing of an FCEM, but ISO plans to return with further discussion on this topic in May

Today's discussion focuses on several key design details

- Continued discussion of the straw FCEM and net carbon pricing frameworks
- These include consideration of key design elements that were discussed in March, but for which the straw frameworks did not recommend a specific approach, including:
  - Integration of an FCEM with existing state policies (e.g., RECs)
  - Treatment of storage resources
- Also offer a preliminary response to stakeholder comments
- Analysis Group will also kick off discussion of modeling approach and assumptions it will employ to evaluate the straw FCEM and net carbon pricing frameworks

Appreciate continued stakeholder engagement and feedback

- ISO welcomes feedback and questions associated with each straw framework put forth
  - Comments can be provided during committee discussions or in writing to Chris Geissler (cgeissler@iso-ne.com) and the Chair of the Participants Committee (or designee)
- Since March meeting, received written comments that are posted for the NEPOOL meeting
  - Comments touch on numerous topics related to the Pathways efforts, including tradeoffs between a net carbon pricing framework and FCEM, interactions with existing policies, and modeling assumptions
  - Today's discussion will consider some of these topics
  - Discussion of these topics will continue at future meetings

ISO has published two new memoranda for this meeting

- **Integration with existing state policy memo**: Provides further consideration of approaches to integrate an FCEM with existing state environmental policies
- **Storage memo**: Discusses role of storage in the region's transition and its potential treatment under FCEM and net carbon pricing frameworks
- These memoranda, as well as those published for the March meeting, are available on the NEPOOL website
- Discuss contents from these new memoranda in more detail in the slides that follow

INTERACTION WITH EXISTING STATE PROGRAMS

Background

- States have existing programs that award certificates for renewable or environmental attributes
- Stakeholders have questioned the extent to which new CECs would be integrated with the existing programs for modelling purposes
- The ISO provided some thoughts in the FCEM Scoping materials and this presentation continues those discussions
- The ISO welcomes continued feedback on this topic and looks forward to further discussion

Three Potential Approaches

- Stakeholders and the ISO are considering three potential modelling approaches for how the FCEM would interact with existing state programs
- **Approach 1**: Clean energy is a new environmental attribute that is distinct from other attributes (e.g., renewable) so that a clean resource can earn both CECs and RECs with each MWh of energy production during the delivery year
- **Approach 2**: Clean energy certificates include all environmental attributes so that a clean resource that sells CECs in the FCEM cannot also sell RECs in the delivery year
- **Approach 3**: The existing programs are discontinued and the region uses clean energy certificates to meet its environmental objectives

Overview of Six Cases

- This section presents six cases that demonstrate total payments to resources under the different approaches with different relationships between CEC demand and REC demand
- The cases consider a stakeholder concern where, under Approach 1, resources that can sell both CECs and RECs may see increased payments relative to Approach 2
  - Following stakeholders, we refer to this as “double payment”
- The cases also explore the extent to which the approaches can yield equivalent results
- For more details on these cases, please see the corresponding “FCEM and Existing State Programs” memo

Parameter Summary

		Clean 1	Clean 2	Renewable 1	Renewable 2
[1]	Unrecovered Costs	$10/MWh	$15/MWh	$20/MWh	$25/MWh
[2]	Max Certificate Award	5,000 MWh	5,000 MWh	5,0000 MWh	5,000 MWh
[3]	Qualified to Sell RECS?	No	No	Yes	Yes
[4]	Qualified to Sell CECs?	Yes	Yes	Yes	Yes

- All six cases consider the same four resources with the same parameter values
  - The "Clean" resources can sell only CECs while the "Renewable" resources can sell CECs and RECs
- Max Certificate Award is the maximum amount of RECs or CECs the resources can sell

Parameter Summary, Cont.

- Unrecovered costs represents the per MWh payment the resources would need to be economical
  - For example, for Clean 1 to be built and provide clean energy, it would need to be paid $10/MWh from either CECs or RECs
  - Note that the "Clean" resources have smaller unrecovered costs than the "Renewable" resources
  - This is a simplifying assumption and, in practice, we'd expect some "Renewable" resources to have lower costs than some "Clean" resources
- Cases assume that the markets for CECs and RECs are competitive, so that resources that set the price for CECs or RECs are paid just enough to "break even" and recover their costs

Case A: Preview

- Case A considers how the resources would clear for certificates under current market rules
  - No CEC demand
  - Only “Renewable” resources will clear for certificates
- Case A provides a baseline for Cases B through F
- Each case’s table provides certificate awards, certificate prices, and the per MWh payment to each resource

Case A: Current Market Rules, No CEC Demand

		Clean 1	Clean 2	Ren. 1	Ren. 2
[1]	REC Demand	8,000 MWh			
[2]	CEC Demand	-			
[3]	REC Award	0 MWh	0 MWh	5,000 MWh	3,000 MWh
[4]	CEC Award	-	-	-	-
[5]	REC Price	$25/MWh			
[6]	CEC Price	-			
[7]	Resource Revenue/MWh	$0/MWh	$0/MWh	$25/MWh	$25/MWh
[8]	Total REC Payments	$200,000			
[9]	Total CEC Payments	-			
[10]	Total Payments	$200,000			

Case A: Fewer "Clean" Resources Clear Under Current Market Rules

- Renewable 1 clears for its entire capability so Renewable 2 is marginal as it provides 3,000 MWh of renewable energy
- Because Renewable 2 is marginal for RECs, it sets the REC price at $25/MWh
- **Key Takeaway**: Without CEC demand, no clean resource receives an award and there is no compensation for clean energy; neither clean resource is built and the region doesn't receive any clean energy beyond what is provided by the two renewable resources

Case B: Preview

- Case B introduces CECs under Approach 1
  - Resources can sell CECs and RECs with the same MWh of energy
- REC demand remains constant at 8,000 MWh but CEC demand is introduced at 9,000 MWh
- A key point of interest is the renewable resources' per MWh payments when they receive both CECs and RECs

Case B: Approach 1, CEC Demand>REC Demand

		Clean 1	Clean 2	Ren. 1	Ren. 2
[1]	REC Demand	8,000 MWh			
[2]	CEC Demand	9,000 MWh			
[3]	REC Award	0 MWh	0 MWh	5,000 MWh	3,000 MWh
[4]	CEC Award	1,000 MWh	0 MWh	5,000 MWh	3,000 MWh
[5]	REC Price	$15/MWh			
[6]	CEC Price	$10/MWh			
[7]	Resource Revenue/MWh	$10/MWh	$0/MWh	$25/MWh	$25/MWh
[8]	Total REC Payments	$120,000			
[9]	Total CEC Payments	$90,000			
[10]	Total Payments	$210,000			

Case B: With Approach 1, No "Double Payment" to Renewables

- Renewables 1 and 2 receive the same REC award
- Under Approach 1, they are also awarded 5,000 MWh of CECs and 3,000 MWh of CECs, respectively
- Clean 1 clears for 1,000 MWh to meet the remainder of the CEC demand. Clean 1 is marginal for CECs and so sets the CEC price at $10/MWh
- Renewable 2 remains marginal for RECs, but because Renewable 2 receives $10/MWh for each CEC it's awarded, it only needs to be paid $15/MWh for RECs to break even. Renewable 2 thus sets the REC price at $15/MWh
- **Key Takeaway:** Resource Revenue/MWh for the two renewable resources is unchanged from Case A: the introduction of CECs under Approach 1 doesn't result in "double payment" to the renewable resources

Case C: Preview

- Case C continues with Approach 1 but increases CEC demand by 10,000 MWh to 19,000 MWh
- Case C sets up a comparison between Approaches 1 and 3 in Case D
- Case C shows that a sufficiently large CEC demand can render the REC demand non-binding

Case C: Approach 1, CEC Demand>>>REC Demand

		Clean 1	Clean 2	Ren. 1	Ren. 2
[1]	REC Demand	8,000 MWh			
[2]	CEC Demand	19,000 MWh			
[3]	REC Award	0 MWh	0 MWh	5,000 MWh	4,000 MWh
[4]	CEC Award	5,000 MWh	5,000 MWh	5,000 MWh	4,000 MWh
[5]	REC Price	$0/MWh			
[6]	CEC Price	$25/MWh			
[7]	Resource Revenue/MWh	$25/MWh	$25/MWh	$25/MWh	$25/MWh
[8]	Total REC Payments	$0			
[9]	Total CEC Payments	$475,000			
[10]	Total Payments	$475,000			

Case C: With Sufficiently Large CEC Demand, REC Price May be $0/MWh

- Clean 1, Clean 2, and Renewable 1 all clear for their maximum capabilities, so Renewable 2 is marginal for both RECs and CECs.
- The REC demand is no longer binding: the 9,000 MWhs of RECs awarded is greater than the 8,000 MWh of demand; the REC clearing price is $0
- **Key Takeaway**: CEC demand is still binding and Renewable 2 sets the CEC price at $25/MWh
  - This price is necessary for Renewable 2 to break even and recover their costs because, in this case, they receive no CEC revenue
- Per MWh compensation to the renewable resources is unchanged at $25/MWh; no "double payment" occurs

Case D: Approach 3, No REC Demand

- If the REC demand would be non-binding under Approach 1 as in Case C, eliminating the REC demand has no effect on CEC pricing, resource payment per MWh, or total payments to resources
- **Key Takeaway:** When CEC demand is sufficiently large compared to REC demand, Approaches 1 and 3 yield equivalent results
- For more details on Case D, see the "FCEM and Existing State Programs" memo or the Appendix slides on Case D

Case E: Preview

- Case E considers Approach 2 where renewable resources can be awarded CECs or RECs, but not both
- To ease comparison, REC and CEC demand are set to their Case B values
  - CEC demand = 9,000 MWh
  - REC demand = 8,000 MWh
- Because renewable resources cannot be awarded CECs when they earn RECs, they can produce clean energy without contributing towards clean energy demand

Case E: Approach 2, CEC Demand>REC Demand

		Clean 1	Clean 2	Ren. 1	Ren. 2
[1]	REC Demand	8,000 MWh			
[2]	CEC Demand	9,000 MWh			
[3]	REC Award	0 MWh	0 MWh	5,000 MWh	3,000 MWh
[4]	CEC Award	5,000 MWh	4,000 MWh	0 MWh	0 MWh
[5]	REC Price	$25/MWh			
[6]	CEC Price	$15/MWh			
[7]	Resource Revenue/MWh	$15/MWh	$15/MWh	$25/MWh	$25/MWh
[8]	Total REC Payments	$200,000			
[9]	Total CEC Payments	$135,000			
[10]	Total Payments	$335,000			

Case E: Approach 2 Can Over-procure Clean Energy Relative to Demand

- With Approach 2, renewable resources can be compensated for either CECs or RECs, but not both
- Resource 2 is marginal for RECs and sets the REC price at $25/MWh
- Clean 2 is marginal for CECs and sets their price at $15/MWh
- **Key Takeaway**: Despite the fact that CEC demand is only 9,000 MWh, the resources sell 17,000 MWh of energy that could yield CECs
  - The remaining 8,000 MWh is used to satisfy REC demand
  - Total payment to resources in Case E ($335,000) is higher than in Case B ($210,000) despite the fact that the two approaches purchase the same quantity of certificates

Case F: Approach 2, CEC Demand is Adjusted to Account for Clean Energy Provided by REC Demand

- Case E over-procures clean energy relative to CEC demand because CEC demand isn't adjusted to account for the clean energy provided by renewable resources that aren't awarded CECs under Approach 2
- **Key Takeaway**: Approaches 1 and 2 can yield equivalent results when CEC demand is adjusted to account for the clean energy provided by resources that are awarded RECs
- For more details on Case F, see the "FCEM and Existing State Programs" memo or the Appendix slides on Case F

Key Observations from the Six Cases

1. The cases suggest that a "double payment" problem is unlikely to occur under Approach 1
2. Approaches 1 and 3 yield equivalent outcomes when CEC demand is sufficiently large compared to REC demand
3. Approach 2 can lead to additional payments compared to Approach 1, but the two approaches can yield equivalent results when CEC demand is reduced to account for the existing REC programs

Conclusion

- Given the three observations above, the ISO proposes for stakeholder consideration that AGI assume Approach 1 for modelling purposes
- Approach 1 appears relatively simple to model, avoids the "double payment" concern identified by stakeholders, and allows for the continuation of the existing state programs
- The ISO has not finalized its thinking on this issue and welcomes stakeholder feedback on the approach proposed, particularly as it may relate to stakeholders' goals for the FCEM framework

ROLE OF STORAGE IN FCEM AND NET CARBON PRICING FRAMEWORKS

Treatment of storage requires careful consideration

- Storage is unlike other energy supply, and this introduces challenges in assessing its treatment under both frameworks
- Rather than producing electricity from a primary energy source (e.g., fossil fuel, nuclear, wind, PV), storage supplies electricity during on-peak hours by storing energy from electricity produced by other generating resources during off-peak hours
- Storage resources can contribute to the region's decarbonization by transferring energy production from higher emitting resources during on-peak hours to lower- and non-emitting resources during off-peak hours

Storage requires careful consideration under both frameworks

- ISO believes that it is important for storage to be compensated for its contributions to meeting the region's environmental objectives
- Stakeholders offered a number of observations about storage's role in the future grid at the March meeting
  - Included discussion of whether it is appropriate for storage to receive clean energy certificates for its energy supply under an FCEM
- In response to these observations, ISO indicated that it would assess how storage can be compensated for these contributions

Storage memo: key observations

- Memo uses a series of numerical examples to examine storage's treatment under both an FCEM and net carbon pricing framework
- Examples show that storage will be compensated for its marginal contributions to clean energy production under an FCEM framework even when it is not awarded clean energy certificates for its energy supply
  - Notably, awarding storage clean energy certificates would lead it to be compensated at a rate that exceeds its contributions
- Storage also will be compensated for its marginal contributions to reducing carbon emissions under a net carbon pricing framework when, as a supplier, it is not charged for carbon emissions

Clean resources will reduce energy offer prices under an FCEM

- Storage can contribute to clean energy production by transferring energy generation from resources that are not clean to those that are clean
- Under an FCEM, clean resources will reduce their energy market offer price to reflect the value of receiving clean energy certificates
  - Similar to how renewable resources may reduce their energy offer price to account for the value of RECs under current market rules
- Resources that do not produce clean energy will not reduce their energy market offer

FCEM increases energy market revenues for storage resources that increase clean energy production

- Storage can increase clean energy production by charging when the marginal supplier is clean (increasing supply from clean generators), and discharging when the marginal supplier is not clean (reducing supply from non-clean generators)
- In such cases, the FCEM will reduce the energy price when the storage resource is charging, but not when it is discharging
- This results in increased energy market revenues for the storage resource because it is now charged a lower price to consume electricity than under current market rules, but it is credited the same price when supplying electricity

Example b1 illustrates a case where storage increases clean energy production

- In this example, a storage resource's participation leads to increased energy generation by a clean baseload resource during an off-peak hour, and reduces energy generation by a non-clean peaker resource during an on-peak hour
- This results in increased total clean energy production across the off-peak and on-peak hours because the storage resource's participation effectively transfers generation from the non-clean peaker to the clean baseload resource
- It is therefore appropriate that the storage resource is compensated for this contribution

The FCEM compensates the storage resource for these clean energy contributions via increased energy market revenues

- This compensation takes the form of an increased price spread between the on-peak hour when the storage resource sells electricity, and the off-peak hour when it buys electricity
  - The energy price decreases in the hour when it is charging (that is, buying energy) by the full value of these clean energy certificates
  - The energy price does not change in the hour when it is discharging (that is, selling energy)
- The increased energy market revenue reflects the marginal value of its contributions to clean energy production
  - The storage resource's revenues increase by $10 per MWh of energy charged, the value of a clean energy certificate, because the energy price when it is charging decreases by this amount

Compensation should align with, but not exceed, a resource's contributions to clean energy

- If the storage resource also received clean energy certificates, this would result in it being compensated twice for its clean energy contributions
- **First**, it would receive increased energy market revenues (as explained on the previous slide)
- **Second**, it would now also receive revenues from clean energy certificates
- Such compensation would therefore exceed its contributions to clean energy production

Certificates should be awarded to suppliers that produce clean energy

- As illustrated in example b2, awarding clean energy certificates to storage resources (in addition to their energy revenue increases) may allow them to receive certificates when they do not increase clean energy production
- Awarding certificates could then cause storage resources to charge and discharge (cycle) when not improving system efficiency or environmental outcomes
- Awarding certificates for such cycling will also reduce the quantity of clean energy certificates that are available to other types of generation, and may adversely impact the region's ability to increase its clean energy production

Storage under net carbon pricing framework

- Memo considers the same examples under a net carbon pricing framework
- Examples illustrate that, when storage resources are not charged for carbon emissions, they are appropriately compensated for their marginal contributions to reducing carbon emissions
- The logic is similar to that for clean energy production under the FCEM framework

Storage under net carbon pricing framework

- The energy price will account for the carbon emissions of the marginal supplier, where the price adder will be larger during periods when the marginal emissions rate is greater
- Thus, if the storage resource transfers energy generation from periods where the marginal supplier emits carbon at a higher rate to those where it emits carbon a lower rate, a net carbon price will increase the energy market price spread
- This increase in the price spread will reflect the storage resource's marginal contribution to reducing carbon emissions
- Illustrated in examples c1 and c2 of the memo

Net carbon pricing compensates storage for environmental contributions under a broader set of conditions

- Under a net carbon pricing framework, storage will generally see increased revenues when its participation reduces carbon emissions
- This includes instances when this reduction in carbon emissions does not result in greater clean energy production
- For example, examples b2 and c2 of the memo shows how a net carbon price will increase storage's revenue when transferring energy production from a higher- to lower-emitting resource, whereas an FCEM framework will not

Storage memo: key takeaways

- Storage is compensated for its marginal contributions to clean energy production under an FCEM framework via increased energy market revenues
- Awarding storage clean energy certificates would lead it to be compensated at a rate that exceeds its contributions, inconsistent with sound market design
- Under a net carbon pricing framework, storage is compensated for its marginal contributions to reducing carbon emissions when it is not charged for carbon emissions

CONTINUED ASSESSMENT OF OTHER FRAMEWORK DETAILS

ISO response to stakeholder comments

- ISO appreciates the thoughtful comments regarding FCEM elements, and broader modeling considerations, including those regarding negative prices and potential changes to the forward capacity market
  - ISO continues to assess several of the comments regarding broader modeling considerations as we move into that part of the study discussion
- Today we have some preliminary observations regarding a request that the FCEM framework should provide clean energy certificates be awarded to low-emitting resources

ISO does not propose to a model clean energy certificates being awarded to emitting resources

- As noted in the FCEM scoping memo, the ISO generally seeks to align design elements with three criteria:
  1. Consistent with stakeholder preferences
  2. Sound market design principles
  3. Simple to model
- Numerous stakeholders have signaled support for a more limited eligibility criteria
- This clean energy definition may be more complex, especially if it also includes the introduction of partial certificates
- Net carbon pricing may offer information about how such an approach would affect market outcomes
- Welcome stakeholder feedback on this broader eligibility criteria

ISO continues to evaluate a conceptual ICCM approach for modeling purposes

- At the March meeting, the ISO provided a memo offering some initial thoughts on a conceptual ICCM approach that could be considered in the modeling efforts
- Stakeholders have expressed interest in understanding an ICCM construct further, including:
  - Clearing and pricing outcomes, and how they may differ between sequential and integrated clearing
  - How the modeling efforts can accommodate integrated and/or sequential clearing of these products
- Continue to welcome stakeholder feedback on this topic
- ISO plans to assess these questions further, and return to stakeholders with more information at future meetings

ISO looks forward to working with stakeholders to evaluate Pathways to the Future Grid

- With the help of stakeholders and the Analysis Group, ISO will evaluate market outcomes under the forward clean energy market and net carbon pricing frameworks
- Welcome stakeholder feedback on these efforts, including the two frameworks to be studied
- Look forward to discussing the modeling approach at future stakeholder meetings
- Share final report on modeled market outcomes with stakeholders in the first quarter of 2022

APPENDIX: INTERACTION WITH EXISTING STATE PROGRAMS, CASES D AND F

Appendix: Case D, Approach 3, No REC Demand

		Clean 1	Clean 2	Ren. 1	Ren. 2
[1]	REC Demand	-			
[2]	CEC Demand	19,000 MWh			
[3]	REC Award	-	-	-	-
[4]	CEC Award	5,000 MWh	5,000 MWh	5,000 MWh	4,000 MWh
[5]	REC Price	-			
[6]	CEC Price	$25/MWh			
[7]	Resource Revenue/MWh	$25/MWh	$25/MWh	$25/MWh	$25/MWh
[8]	Total REC Payments	-			
[9]	Total CEC Payments	$475,000			
[10]	Total Payments	$475,000			

- CEC demand at 19,000 MWh, REC demand set to 0 MWh

Appendix: Approaches 1 and 3 Will Yield the Same Results When REC Demand is Not Binding

- Renewable 2 is still marginal for CECs as the other resources clear for their entire capabilities
- Renewable 2 sets the CEC price at $25/MWh
- **Key Takeaway**: Approaches 1 and 3 will yield the same results when REC demand is not binding, as occurred with Case 3
  - If REC demand is binding, Approach 1 will yield different outcomes than Approach 3
  - Without REC demand, fewer renewable resources and more clean (but not renewable) energy resources would likely clear

Appendix: Case F, Approach 2, CEC Demand<REC Demand

		Clean 1	Clean 2	Ren. 1	Ren. 2
[1]	REC Demand	8,000 MWh			
[2]	CEC Demand	1,000 MWh			
[3]	REC Award	0 MWh	0 MWh	5,000 MWh	3,000 MWh
[4]	CEC Award	1,000 MWh	0 MWh	0 MWh	0 MWh
[5]	REC Price	$25/MWh			
[6]	CEC Price	$10/MWh			
[7]	Resource Revenue/MWh	$10/MWh	$0/MWh	$25/MWh	$25/MWh
[8]	Total REC Payments	$200,000			
[9]	Total CEC Payments	$10,000			
[10]	Total Payments	$210,000			

- To avoid over-procuring CECs relative to demand, CEC demand is reduced to account for REC demand

Appendix: Approaches 1 and 2 Can Yield the Same Results When CEC Demand is Adjusted to Account for REC Demand

- Renewable 2 is marginal for RECs and sets the REC price at $25/MWh
- Clean 1 is marginal for CECs and sets the CEC price at $10/MWh
- Per MWh payments to the resources (Row [7]) and total payments (Row [10]) are identical across Cases B and F
- **Key Takeaway**: It is possible to achieve the same outcomes with Approaches 1 and 2 by adjusting CEC demand to account for REC demand

memo

To: NEPOOL Participants Committee Working Session

From: Market Development

Date: April 8, 2021

Subject: The FCEM and Existing State Programs

Introduction

Stakeholders and the ISO are scoping the framework for a "Forward Clean Energy Market" (FCEM) that would procure clean attribute certificates (CECs) years in advance. We seek to clarify necessary scoping details so that the ISO and the Analysis Group (AGI) can complete the modelling framework for quantitative analysis. A key outstanding question is the extent to which the new CECs would be integrated with existing state programs, which are designed to help facilitate the development of resources with specific environmental attributes. Because this design choice will likely affect CEC and REC pricing, it may be important for modelling purposes. The ISO and stakeholders are evaluating three approaches, summarized below:[1]

Approach 1: Clean energy certificates reflect a clean attribute that is distinct from and does not overlap with other environmental attributes so that clean resources that are eligible can earn both CECs and renewable energy certificates (RECs) with each MWh of energy production during the delivery year.

Approach 2: Clean energy certificates encompass all environmental attributes, so that a resource that chooses to sells CECs in the FCEM cannot also sell a REC in the delivery year for the same MWh.[2]

Approach 3: The existing programs are discontinued, and the region uses clean energy certificates to meet its environmental objectives.

This memo considers six cases (labelled A through F) that demonstrate total payments to resources under the different approaches and with different relationships between CEC demand and REC demand. In the numerical examples, there are two renewable resources that produce both renewable and clean energy, and therefore can sell both CECs and RECs, and two clean resources that can sell only CECs. The cases assume competitive markets for both CECs and RECs, meaning that the price that is set for each of these

[1] See Section 4 of the FCEM Scoping memo, https://nepool.com/wp-content/uploads/2021/03/NPC_FG_20210318_Supplemental-1.pdf.

[2] Approach 2 would require clear rules regarding how a resource eligible to produce either a CEC or a REC would determine which type of credit it would like to generate.

certificates is based on the "break even" cost that must be recovered by the marginal resource that provides this product, outside of revenue from other markets such as the real-time energy market. The table below summarizes the cases, their assumptions, and key takeaways.

Summary of Cases and Results			
	Approach	**Relationship between REC and CEC Demand**	**Key Takeaways**
Case A	Current Market Rules	Only REC Demand	Under current market rules, resources recover their costs through REC revenue. Total payment for certificates is $200,000.
Case B	Approach 1	CEC Demand > REC Demand	CEC demand is introduced and is greater than REC demand. Resources can now recover costs through REC and/or CEC revenue. Total payment for RECs and CECs is $210,000, with the increase compared to Case A due to the increased quantity of clean energy. The resources that sell CECs and RECs don't receive double payment compared to Case A.
Case C	Approach 1	CEC Demand >>> REC Demand	CEC demand is set far greater than REC demand. The REC constraint is not binding and the REC price is $0/MWh. Total payments increase to $475,000, reflecting the larger quantity of clean energy demanded. No double payment occurs.
Case D	Approach 3	Only CEC Demand	CEC demand is kept at the higher level but the state REC programs are discontinued so that there is no REC demand. This case clears the same quantity of MWhs from the same resources at the same price as Case C. When CEC demand is sufficiently large relative to REC demand, Approach 1 and Approach 3 yield equivalent results.
Case E	Approach 2	CEC Demand > REC Demand	CEC demand is set as in Case B but we assume Approach 2. The renewable resources satisfy the REC demand and the clean resources satisfy the clean energy demand. Total payments are $335,000, larger than Case B's total payments = $210,000. This increase in payments reflects the fact that more clean MWhs have to clear to meet the same clean energy demand.
Case F	Approach 2	CEC Demand < REC Demand	CEC demand is decreased to avoid purchasing excess clean energy. Total payment for RECs and CECs is $210,000, as in Case B.

The cases demonstrate three key points:

1. Stakeholders have expressed concern about the possibility of "double payments" under Approach 1, where resources that can sell both CECs and RECs will see increased payments per MWh of energy relative to Approach 2 and Current Market Rules. The examples suggest that such double payments may not materialize because CEC and REC prices adjust to ensure that marginal resources that are capable of selling both CECs and RECs will recover their costs, but no more than that amount.[3]

2. Approach 1 and Approach 3 yield equivalent outcomes when CEC demand is sufficiently large compared to REC demand, because this may lead to a quantity of renewable energy that is greater than or equal to the state requirements.

3. Approach 2 can lead to additional payments compared to Approach 1. Approaches 1 and 2 may yield equivalent results when CEC demand is reduced to account for the existing programs, but it

[3] Costs here, and throughout the memo, refer to incremental costs that the resource does not expect to recover through other wholesale markets, like the real-time energy market and capacity market.

may be difficult to make these approaches equivalent in practice, given the large number of state programs, where these each have different eligibility criteria, non-compliance rates, etc.

Given the above observations, the ISO proposes that AGI assume Approach 1 for the straw FCEM framework, as this appears to align most appropriately with the criteria the ISO identified for choosing between design options.[4] More specifically, it appears relatively simple to model, avoids the double payment concern identified by stakeholders, and allows for the continuation of the existing state programs. However, as the examples in this memo show, this approach may produce similar outcomes as Approach 2.

This memo, however, should not suggest that the ISO has finalized its thinking on the extent to which the existing programs should be integrated with the new CECs for the purposes of modelling. Indeed, the ISO welcomes stakeholder feedback on the proposed approach, particularly as it may relate to stakeholder's goals for the FCEM framework, and looks forward to further discussion.

Case A: Current Market Rules

Table 1 below summarizes the parameter values for the resources in all six cases considered in this memo. In each of the cases, there are two clean resources (Clean 1 and Clean 2) that can sell only CECs, and two renewable resources (Renewable 1 and Renewable 2) that can sell both CECs and RECs. The renewable resources are assumed to have greater costs and so need to be compensated at a higher rate to be economical.[5] For example, Renewable 2 would need to be paid at least $25/MWh for their clean energy or renewable attributes. If they are not paid at least this much, their resource will not be built. Clean 1, on the other hand, has fewer costs and so only needs to be paid $10/MWh to be built. All four resources have the same maximum certificate award of 5,000 MWh, so that no resource can sell more than 5,000 MWhs of CECs and the two renewable resources cannot sell more than 5,000 MWhs of RECs. Note that for simplicity and ease of comparison, we assume each resource submits fully rationable offers, so that there is no lumpiness in REC or CEC awards. Finally, we assume that the markets for both the RECs and the CECs are competitive, so that the marginal resource breaks even on their investment.

Table 1: Parameter Summary for Resources

		Clean 1	Clean 2	Renewable 1	Renewable 2
[1]	Unrecovered Costs/MWh	$10	$15	$20	$25
[2]	Maximum Certificate Award	5,000 MWh	5,000 MWh	5,0000 MWh	5,000 MWh
[3]	Qualified to Sell RECS?	No	No	Yes	Yes
[4]	Qualified to Sell CECs?	Yes	Yes	Yes	Yes

While all six cases assume these same resource properties, they will produce different results based upon assumptions about the demand for each environmental attribute and whether resources can receive both

[4] For further discussion of these criteria, see the ISO's memo on the straw FCEM framework, available at https://nepool.com/pathways-study-process/1a-fcem-scoping-memo_vfinal/.

[5] Because resources that qualify as renewable must have additional attributes, they generally have higher costs than resources that are only "clean." In practice, some resources that qualify as renewable may be cheaper than other resources that qualify as "clean."

clean and renewable energy certificates for each MWh produced. These cases begin with current market rules, where there are renewable energy credits, but no clean energy credits.

Under current market rules, there are no CECs so the resources can only recover their costs with REC revenue. The table below summarizes the results for Case A, where the REC demand is set at 8,000 MWh.[6]

Case A: Current Market Rules, No CEC Demand					
		Clean 1	Clean 2	Renewable 1	Renewable 2
[1]	REC Demand	8,000 MWh			
[2]	CEC Demand	-			
[3]	REC Award	0 MWh	0 MWh	5,000 MWh	3,000 MWh
[4]	CEC Award	-	-	-	-
[5]	REC Price	$25/MWh			
[6]	CEC Price	-			
[7]	Resource Revenue/MWh	$0/MWh	$0/MWh	$25/MWh	$25/MWh
[8]	Total REC Payments	$200,000			
[9]	Total CEC Payments	-			
[10]	Total Payments	$200,000			

In this case, Renewable 1 clears for its entire capability so Renewable 2 is marginal as it provides 3,000 MWh of renewable energy. Because Renewable 2 is the marginal resource for RECs, it sets their price at its "breakeven" cost of $25/MWh. In total, the resources sell 8,000 MWh of RECs and so satisfy the REC requirement. Total payments to the resources is $200,000.

Note that, without CEC demand, there is not compensation for clean energy. Thus, the clean resources that are eligible only for CECs earn no incremental revenues from the sale of environmental attributes. As a result, neither clean resource is developed and the region's energy mix doesn't include any clean energy beyond what is provided by the two renewable resources.

Case B: CEC Demand > REC Demand, Approach 1

Under Approach 1, the renewable resources can sell both CECs and RECs for the same MWhs. Assume the CEC demand is 9,000 MWh, REC demand remains unchanged from Case A at 8,000 MWh, and that the resources have the same parameter values as in Table 1. The table below summarizes the results for Case B.

[6] For simplicity, we assume the demand bids are vertical.

Case B: CEC Demand > REC Demand, Approach 1					
		Clean 1	Clean 2	Renewable 1	Renewable 2
[1]	REC Demand	8,000 MWh			
[2]	CEC Demand	9,000 MWh			
[3]	REC Award	0 MWh	0 MWh	5,000 MWh	3,000 MWh
[4]	CEC Award	1,000 MWh	0 MWh	5,000 MWh	3,000 MWh
[5]	REC Price	$15/MWh			
[6]	CEC Price	$10/MWh			
[7]	Resource Revenue/MWh	$10/MWh	$0/MWh	$25/MWh	$25/MWh
[8]	Total REC Payments	$120,000			
[9]	Total CEC Payments	$90,000			
[10]	Total Payments	$210,000			

As in Case A, the least cost way to meet the REC demand is to award Renewable 1 with 5,000 MWh of RECs and Renewable 2 with 3,000 MWh of RECs. With Approach 1, Renewable 1 and Renewable 2 can be awarded CECs in addition to RECs, and so Renewables 1 and 2 also receive 5,000 MWh and 3,000 MWh of CECs, respectively. To meet the remainder of CEC demand, Clean 1 provides the final 1,000 MWh at least cost.

While the change in awards from Case A is modest, the pricing implications are important. First, Clean 1 is now marginal for CECs and so sets the CEC price. That is, if the CEC demand was increased by 1 MWh, Clean 1 would clear for an additional MWh of CEC at a cost of $10. This increase in costs sets the CEC price at $10/MWh. Note that this price is the "break even" price for Clean 1.

Second, Renewable 2 remains marginal for RECs. However, because Renewable 2 receives $10/MWh for each CEC it is awarded, it can recover its costs while receiving a lower REC payment than in Case A. More specifically, Renewable 2 only needs to be paid $15/MWh for RECs to break even as this will result in it fully recovering its costs of $25/MWh ($15 for each REC sold, and another $10 for each CEC sold). As a result, Renewable 2 sets the REC price at $15/MWh.

Note that despite the fact that the two renewable resources are paid twice for each MWh, their total compensation per MWh is still $25. (Row [7] is the same in both of the above tables for the two renewable resources.) Thus, the double payment concern that has been highlighted with respect to Approach 1 does not appear to materialize.

Finally, note that the total payment to the resources for both CECs and RECs is $210,000. The additional $10,000 in total payments in Case B compared to Case A reflects Clean 1's cost for providing CECs.

Case C: CEC Demand >>> REC Demand, Approach 1

Continuing with Approach 1, Case C is identical to Case B except the CEC demand is increased by 10,000 MWh to 19,000 MWh. The table below summarizes the results for Case C.

Case C: CEC Demand >>> REC Demand, Approach 1					
		Clean 1	Clean 2	Renewable 1	Renewable 2
[1]	REC Demand	8,000 MWh			
[2]	CEC Demand	19,000 MWh			
[3]	REC Award	0 MWh	0 MWh	5,000 MWh	4,000 MWh
[4]	CEC Award	5,000 MWh	5,000 MWh	5,000 MWh	4,000 MWh
[5]	REC Price	$0/MWh			
[6]	CEC Price	$25/MWh			
[7]	Resource Revenue/MWh	$25/MWh	$25/MWh	$25/MWh	$25/MWh
[8]	Total REC Payments	$0			
[9]	Total CEC Payments	$475,000			
[10]	Total Payments	$475,000			

Clean 1, Clean 2, and Renewable 1 all clear for their maximum capabilities, so Renewable 2 is marginal for both RECs and CECs. Note, however, that the REC demand is no longer binding: the 9,000 MWhs of RECs awarded is greater than the 8,000 MWh demand.[7] As a result, the REC clearing price is $0/MWh. The CEC demand is still binding, however, and Renewable 2 sets the CEC price at $25/MWh. Note that this $25/MWh CEC price is necessary for Renewable 2 to break even and recover their costs because, in this case, they expect no additional revenue from RECs.

The total payment to the resources for both CECs and RECs is $475,000. The additional payments reflect the fact that substantially more CECs are awarded in Case C than in Case B. Despite the additional payments, there is still no “double payment”: the two renewable resources are still paid $25/MWh, as in Case A and Case B. (Row [7] is unchanged for the renewable resources.)

Case D: Approach 3, No REC Demand

With Approach 3, the state programs are assumed to be discontinued so that there is no REC demand. CEC demand is unchanged from Case C at 19,000 MWh. The table below summarizes the results for Case D.

[7] Whether the REC demand bid binds is a function not only of the size of CEC demand, but also of supply conditions. For example, if the maximum capability of clean resources was substantially decreased, the REC demand could be rendered non-binding in Case B as well.

Case D: No REC Demand, Approach 3						
			Clean 1	Clean 2	Renewable 1	Renewable 2
[1]	REC Demand		-			
[2]	CEC Demand		19,000 MWh			
[3]	REC Award		-	-	-	-
[4]	CEC Award		5,000 MWh	5,000 MWh	5,000 MWh	4,000 MWh
[5]	REC Price		-			
[6]	CEC Price		$25/MWh			
[7]	Resource Revenue/MWh		$25/MWh	$25/MWh	$25/MWh	$25/MWh
[8]	Total REC Payments		-			
[9]	Total CEC Payments		$475,000			
[10]	Total Payments		$475,000			

Renewable 2 is still marginal for CECs, as Clean 1, Clean 2, and Renewable 1 clear for their entire capability. Without REC demand, there is no REC price, and the resources recover their costs entirely from CECs. As in Case C, the total payment to the resources is $475,000, and the renewable resources are paid $25/MWh. There is no double payment to the renewable resources.

Note that Approaches 1 and 3 will generally yield the same results when REC demand is not binding, as occurred with Case C. If, however, REC demand is binding, as in Case B, Approach 1 will yield different outcomes than Approach 3. In particular, under Approach 3 without the REC demand, fewer renewable resources and more clean (but not renewable) energy resources are likely to clear than under Approach 2 when REC demand is binding. Approach 3 will generally result in lower costs for the same quantity of clean energy but it will yield less renewable energy.

Case E: CEC Demand > REC Demand, Approach 2

With Approach 2, the renewable resources can be compensated for either CECs or RECs, but not both. More specifically, for the purposes of this memo, we assume that each MWh’s attributes can only be counted for one product. In practice, we expect the resources to sell the highest value certificates, subject to their capability. In this case, where the REC price is higher than CEC price, we expect the renewable resources to sell the RECs and the clean energy resources to sell the CECs. To ease comparisons, CEC and REC demand are the same as in Case B with Approach 1, as illustrated in the table below.

Case E: CEC Demand > REC Demand, Approach 2					
		Clean 1	Clean 2	Renewable 1	Renewable 2
[1]	REC Demand	8,000 MWh			
[2]	CEC Demand	9,000 MWh			
[3]	REC Award	0 MWh	0 MWh	5,000 MWh	3,000 MWh
[4]	CEC Award	5,000 MWh	4,000 MWh	0 MWh	0 MWh
[5]	REC Price	$25/MWh			
[6]	CEC Price	$15/MWh			
[7]	Resource Revenue/MWh	$15/MWh	$15/MWh	$25/MWh	$25/MWh
[8]	Total REC Payments	$200,000			
[9]	Total CEC Payments	$135,000			
[10]	Total Payments	$335,000			

Renewable 2 is marginal for the RECs and sets the REC price at $25/MWh, while Clean 2 is marginal for the CECs and sets their price at $15/MWh. Because the renewable resources cannot sell both CECs and RECs, their total revenue per MWh is $25/MWh. Note that the total revenue to the renewable resources is the same in Case E as in all of the other cases.

Despite the fact that CEC demand is only 9,000 MWh, the resources sell 17,000 MWhs of energy that could yield CECs, where this remaining 8,000 MWh of energy instead is used to satisfy only demand for RECs. As a result, the total overall payment to the resources in Case E ($335,000) is substantially higher than in Case B ($210,000).

Case F: CEC Demand < REC Demand, Approach 2

To avoid the increased costs seen in Case E that result from procuring excess clean energy, Case F reduces CEC demand to 1,000 MWh, so that Cases F and B result in the same total payments. See the table below.

Case F: CEC Demand < REC Demand, Approach 2					
		Clean 1	Clean 2	Renewable 1	Renewable 2
[1]	REC Demand	8,000 MWh			
[2]	CEC Demand	1,000 MWh			
[3]	REC Award	0 MWh	0 MWh	5,000 MWh	3,000 MWh
[4]	CEC Award	1,000 MWh	0 MWh	0 MWh	0 MWh
[5]	REC Price	$25/MWh			
[6]	CEC Price	$10/MWh			
[7]	Resource Revenue/MWh	$10/MWh	$0/MWh	$25/MWh	$25/MWh
[8]	Total REC Payments	$200,000			
[9]	Total CEC Payments	$10,000			
[10]	Total Payments	$210,000			

Once again, Renewable 2 is marginal for RECs and sets their price at $25/MWh. Reducing CEC demand from 9,000 MWh to 1,000 MWh decreases Clean 1 and Clean 2's CEC awards, so that Clean 1 is now marginal for CECs and sets their price at $10/MWh. These prices ensure that each Clean 1 and Renewable 2 both recover their costs and break even. Note that the total resource revenue per MWh (Row [7]) and total payments to the resources (Row [10]) are the same in Cases B and F.

Case F demonstrates that it is possible to achieve the same outcomes with Approaches 1 and 2, as this outcome is effectively equivalent to Case B, where resources are permitted to sell both clean energy certificates and RECs. However, given that there are often many different RECs, where the products vary by state, technology, and location, it may not be practical to adjust clean energy demand to produce an outcome that meets both the region's clean energy targets and its many REC requirements in a cost-effective manner.

Conclusion

The six cases above show that, given competitive REC and CEC markets, we do not expect renewable resources to receive additional revenue per MWh with the introduction of clean energy certificates. However, given the same levels of demand, we do observe increased costs with Approach 2 compared to Approach 1. These increased costs from Approach 2 can be alleviated by adjusting demand, but the ISO believes that this may be difficult in practice, given the large number of overlapping state programs with different eligibility criteria, noncompliance rates, etc. Finally, Approach 1 and Approach 3 will often yield identical results, and when the two approaches yield different results, Approach 3 will generally entail lower costs.

Given these observations, the ISO proposes that, for modelling purposes, AGI assume Approach 1 so that the CECs are not integrated with the existing state programs. This approach appears to be relatively simple to model, avoids the double payment concern identified by stakeholders, and allows for the continuation of the existing state programs. The ISO has not finalized its thinking on this issue, however, and welcomes stakeholder input and feedback in the coming weeks as we move towards a decision.

ISO new england

memo

To: NEPOOL Participants Committee Working Session

From: Market Development

Date: April 8, 2021

Subject: Storage Resources and Pathways to a Future Grid

As the ISO and its stakeholders evaluate pathways to a future grid, a key consideration is the role of storage resources in this transition, and the extent to which the frameworks being evaluated facilitate their participation in the decarbonization of the region's energy sector. While this discussion in ongoing, the ISO prepared this memorandum in order to offer some practical observations about the implications of various treatments for energy storage, including if it is eligible to receive clean energy certificates under an forward clean energy market (FCEM) framework,[1] and how it participates in a net carbon pricing framework.

To evaluate these treatments, the memorandum introduces a series of numerical examples that consider storage's impact on production costs, clean energy production, and carbon emissions. These examples then evaluate storage's compensation under current market rules, an FCEM framework considering cases where storage does and does not receive clean energy certificates, and net carbon pricing.

These examples, summarized in Table 1 below, find that storage resources are compensated for their marginal contributions to clean energy production via increased energy market revenues under an FCEM framework. As such, it is most consistent with sound market design to not award clean energy certificates to storage resources as this would lead them to be compensated at a rate above their clean energy contributions. The examples also find that a net carbon pricing approach that does not charge storage resources for carbon emissions will appropriately compensate them for its contributions to carbon emissions reductions.

[1] In this document, the FCEM refers generally to the forward clean energy procurement framework as has been discussed recently at the NEPOOL Participants Committee and is outlined in the scoping memo, available at https://nepool.com/wp-content/uploads/2021/03/1a-FCEM-Scoping-Memo_vfinal.pdf. The observations provided in this memo apply equally whether the forward procurement of clean energy occurs outside of the Forward Capacity Market (where this is commonly referred to as the FCEM framework), or if this procurement is instead integrated with the Forward Capacity Market (where this approach is commonly referred to as the Integrated Clean Capacity Market, or ICCM).

Table 1: Summary of Examples			
	Market Rules	Storage's Impact on Outcomes	Key Takeaways
Example a1	Current Market Rules	Storage transfers production from peaker to clean baseload resource	Storage is compensated for its contributions to reducing production costs.
Example b1	FCEM	Storage transfers production from non-clean peaker to clean baseload, increases clean energy production.	Storage is compensated for its contributions to reducing production costs and increasing clean energy production without being awarded clean energy certificates.
Example b2	FCEM	Storage transfers production from non-clean peaker to non-clean baseload, does not increase clean energy production.	Storage is compensated for its contributions to reducing production costs without being awarded clean energy certificates.
Example c1	Net Carbon Pricing	Storage transfers production from carbon emitting peaker to non-emitting baseload, reduces carbon emissions.	Storage is compensated for its contributions to reducing both production costs and carbon emissions.
Example c2	Net Carbon Pricing	Storage transfers production from carbon emitting peaker to less carbon emitting baseload, reduces carbon emissions.	Storage is compensated for its contributions to reducing both production costs and carbon emissions. While storage transfers energy production in same manner as Example b2 (where it does not increase clean energy production), under a carbon price framework, it reduces carbon emissions and is compensated as such.

1. Storage's role in the region's decarbonization

Storage's role in energy production differs from that of other technologies, as it charges (withdraws / consumes) during lower priced periods and then discharges (injects / generates) during higher priced periods. Thus, rather than producing energy like a traditional generator, energy storage enhances the market's efficiency by allowing some of the peak load, which is typically supplied by high-cost peaking generation, to be met by lower cost generation stored during off-peak hours. In addition to lowering costs, storage can play an important role in the region's decarbonization. For example, it may allow generation to be shifted from peak hours, where the marginal energy supplier emits greater levels of carbon for each MWh of energy produced, to off-peak hours, where the marginal energy supplier may emit relatively less carbon.[2]

By transferring the energy production to lower emitting resources, storage can help to reduce the region's total carbon emissions. Applying similar logic, storage resources may increase the region's production of clean energy if it shifts energy generation from peak hours when the marginal resource is not producing clean energy to off-peak hours when it is. It is therefore appropriate to evaluate the potential treatment of storage resources under an FCEM or net carbon pricing framework to determine what approach most

[2] While storage may also provide other benefits that help to facilitate the region's decarbonization, such as reliability services, these are outside the scope of this memo.

appropriately compensates them for their environmental contributions in a manner that is commensurate with other resource types.

2. Numerical Examples

While the numerical examples make a number of simplifying assumptions, their findings generalize to a broad set of market and resource conditions. They consider two hours – an off-peak hour when energy demand is low, and an on-peak hour when energy demand is high. They assume that there are two generating resources that can meet this demand. The first generator is a lower cost "baseload" resource, B, which has 100 MW of capacity. This resource is assumed to be marginal during off-peak hours, as its capacity exceeds energy demand, and its offer therefore sets the clearing price in this hour. However, during on-peak hours, it is infra-marginal as demand exceeds its maximum output. In these examples, we consider outcomes when the baseload resource is one of two different kinds of technologies: a clean, non-emitting resource (examples a1, b1, and c1), and a (relatively) low emission, natural gas generator (examples b2 and c2).

The second generator is a higher cost "peaker" resource, P, which also has 100 MW of capacity. This generator does not run during the off-peak hour (as demand can be met entirely by the lower cost "base" resource), but it is needed to meet the higher energy demand during the on-peak hour. In this on-peak hour, resource P is the marginal resource, and its offer sets the clearing price.

Finally, each example considers two cases. In case 1, energy demand in both hours is met entirely by these two generators. In case 2, we introduce a storage resource, S, that charges at a rate of 10 MW during the off-peak hour (meaning total energy supplied from the non-storage generators increases by 10 MWh during this hour), and discharges at a rate of 10 MW during the on-peak hour (meaning total energy supplied by the non-storage generators decreases by 10 MWh).[3]

For simplicity, we assume that this storage resource incurs no costs except for those associated with buying energy during the off-peak hour. In each example, we compare outcomes between these two cases, with a focus on how storage's participation impacts the production costs incurred to meet electricity demand, clean energy production, and carbon emissions.

These assumptions are summarized in Table 2 below.

[3] We assume for simplicity that storage resource is a price-taker as demand in the off-peak hour, and is a price-taker as supply in the on-peak hour. Moreover, for simplicity, we assumes S incurs no losses between charging and discharging. However, the key observations would apply even when storage is not 100 percent efficient.

Table 2: Example Assumptions		
Assumptions Applicable to Both Cases		
Baseload capacity	100 MW	
Peaker capacity	100 MW	
Off-peak demand	80 MWh	
On-peak demand	150 MWh	
Assumptions that Vary Between Cases		
	Case 1: No Storage	**Case 2: Storage**
Off-peak (non-storage) generation	80 MWh	90 MWh
On-peak (non-storage) generation	150 MWh	140 MWh
Total generation	230 MWh	230 MWh

After evaluating storage resource's impact on production costs and environmental outcomes, we consider the storage resource's compensation under case 2. For the FCEM, this includes consideration of market rules that do not award storage clean energy certificates as well as those that do award it such certificates. This analysis seeks to determine which set of market rules better aligns storage's compensation with its marginal contributions to reducing production costs and increasing clean energy production.

a. Compensation for storage resources under current market rules

We begin with an example that employs the current market rules. More specifically, this example assumes that neither an FCEM nor a net carbon price framework is in effect.

Example a1: Storage shifts energy production from the on-peak hour to the off-peak hour

In this example, we assume that the baseload resource B is a clean resource that has "physical" marginal costs[4] of producing electricity of $0 per MWh, and the peaker resource P is a combustion turbine generator with "physical" marginal costs of producing electricity of $100 per MWh. Market outcomes under cases with and without the participation of storage resource S are illustrated in Table a1.1 below.

[4] We define "physical" marginal costs as the costs that the resource incurs to produce electricity before consideration of any environmental costs or rebates. We will use these costs to determine the production costs that are considered in addition to environmental costs or benefits in the examples throughout.

Table a1.1: Energy Awards and Production Costs		
Case 1: No Storage		
	Generation *[MWh]*	Production Costs *[$]*
[1] Off-peak	80 MWh	$0 *[80 MWh × $0/MWh]*
[2] On-peak	150 MWh	$5,000 *[100 MWh × $0/MWh + 50 MWh × $100/MWh]*
[3] Total	230 MWh	$5,000
Case 2: Storage		
	Generation *[MWh]*	Production Costs *[$]*
[4] Off-peak	90 MWh	$0 *[90 MWh × $0/MWh]*
[5] On-peak	140 MWh	$4,000 *[100 MWh × $0/MWh + 40 MWh × $100/MWh]*
[6] Total	230 MWh	$4,000
Change in Costs Due to Storage Participation		
	Generation *[MWh]*	Production Costs *[$]*
[7]	0 MWh	($1,000)

Case 1 is given in the top panel of the table (rows [1] through [3]), where storage resource S does not participate. In this case, the 80 MWh of demand in the off-peak hour is met by the base resource B (row [1]) and the entire 150 MWh of demand in the on-peak hour is met by generation in that hour (row [2]). This results in total production costs of $5,000, where, because the base resource has physical marginal costs of $0 per MWh, these costs come entirely from the 50 MWh provided by peaker P during the on-peak hour. The total generation and production costs are summed across the off- and on-peak hours in row [3].

Case 2 is illustrated in the second panel of the table (rows [4] through [6]), where storage resource S consumes electricity during the off-peak hour, thus increasing off-peak demand by 10 MWh to 90 MWh, as shown in row [4], and discharges this energy during the on-peak hour, thereby reducing on-peak generation by this same 10 MWh to 140 MWh (row [5]).

The impact of the storage resource's participation, measured as its total reduction in production costs, is illustrated in the row [7]. In this example, storage reduces the production costs to meeting demand across these two hours by $1,000 ($100/MWh × 10 MWh) as the costly peaker P now only provides 40 MWh of energy, 10 MWh less than in Case 1. This reduction in production costs is calculated by subtracting the total production costs without storage participation (row [3]) from those with storage participation (row [6]).

In this example, storage resource S is compensated for its contributions to reducing production costs based on the difference between energy prices when it charges and discharges. More specifically, as shown in Table a1.2 below, storage incurs no costs when charging in the off-peak hour because it consumes 10 MWh of electricity at a price of $0 per MWh (row [1]). It then receives total payments equal to $1,000 during the on-peak hour when it discharges because it produces 10 MWh of energy that is sold at $100 per MWh (row [2]). Thus, storage resource S receives total compensation of $1,000 (row [3]), equal to its revenues from energy sold less its costs from energy bought. This compensation is commensurate with the degree to which its shifting energy production from the higher cost peaker P to base resource B reduces the total production costs, as shown by comparing production costs between the cases in Table a1.1 (rows [3] and [6]).[5] Under these current market rules, which do not compensate resources for either for clean energy production or reductions in carbon emissions, storage does not receive any additional compensation for its contributions to these environmental objectives.

Table a1.2: Storage Revenues			
	[a]	*[b]*	*[c] = [a] × [b]*
	Energy Clearing Price	Cleared Supply	Storage Net Revenues
	[$/MWh]	*[MWh]*	*[$]*
[1] Off-peak	$0/MWh	-10 MWh	$0
[2] On-peak	$100/MWh	10 MWh	$1,000
[3]	Total	0 MWh	$1,000

b. Storage's compensation under an FCEM

We now consider a pair of examples that are similar to that presented above, except they now presume that an FCEM is in place and consider two additional factors – how storage contributes to the production of clean energy, and how storage's compensation changes with the introduction of this new market. In each case, we assume that the FCEM specifies a value of $10 per MWh of clean energy produced.[6]

Additionally, consistent with the cost allocation methodology put forth in the straw FCEM framework, we presume that the new costs associated with procuring clean energy certificates are allocated to Real-Time

[5] The energy market price is based on marginal costs and as such, a resource's profits from the energy market are based on its contributions to reducing production costs at the margin. In this example, and those that follow, these profits are also equal to the storage resource's total contributions to reducing production costs (and improving environmental outcomes) because the storage resource's participation does not change the marginal resource in either the off- or on-peak hour, and as a result, its first MWh charged/discharged yields the same reduction in production costs as its last. Thus, while resources are generally compensated based on their marginal contribution to production costs (and environmental outcomes), the assumptions in this example lead the storage resource's compensation to also equal its total contribution to production costs (and environmental outcomes). This assumption helps to simplify the comparison of storage's compensation and contributions to production costs (and environmental outcomes).

[6] The example's takeaways would hold under a range of assumed clean energy certificate prices, where this price reflects the value of a certificate as specified during the delivery period.

Load Obligation (RTLO). This approach does not allocate these new clean energy costs to storage resources when they are charging.[7]

In the first of these examples, we assume that baseload resource B produces clean energy, whereas in the second, we presume that it is an efficient gas-fired combined cycle plant that does not produce clean energy.

Example b1: Storage increases clean energy production

In this example, baseload resource B again produces energy with phystical marginal costs of $0 per MWh. However, these MWh are now considered clean, and thus produce clean energy certificates that are valued at $10 per MWh. This is reflected Table b1.1 below, which builds appears similar to Table a1.1 from the earlier example. This table includes a new column that calculates the total benefit from clean energy production as the product of baseload resource B's production and $10 per MWh (column [c]).[8] In case 1 (no storage participation) where B produces a total of 180 MWh across the two hours, the total clean energy benefit provided is $1,800, equal to the product of 180 MWh of energy generated by clean resource B and the $10 per MWh value associated with this clean energy.

[7] While the memo does not explicitly evaluate approaches that would allocate clean energy costs to storage, such approaches do not appear well-equipped to robustly compensate storage commensurate with their clean energy contributions across a range of market and resource conditions.

[8] Thus, these calculations assume that consistent with the payment rate of $10 per MWh of clean energy production provided to suppliers, the social benefits from an incremental 1 MWh of clean energy production are $10.

Table b1.1: Energy Awards, Production Costs, and Clean Energy Benefits				
	[a]	*[b]*	*[c]*	*[d] = [b] - [c]*
Case 1: No Storage Participation				
	Generation *[MWh]*	Production Costs *[$]*	Clean Energy Benefit *[$]*	**Total Costs *[$]***
[1] Off-peak	80 MWh	$0 *[80 MWh × $0/MWh]*	$800 *[80 MWh × $10/MWh]*	**($800)**
[2] On-peak	150 MWh	$5,000 *[100 MWh × $0/MWh + 50 MWh × $100/MWh]*	$1,000 *[100 MWh × $10/MWh]*	**$4,000**
[3] Total	230 MWh	$5,000	$1,800	**$3,200**
Case 2: Storage Participation				
	Generation *[MWh]*	Production Costs *[$]*	Clean Energy Benefit *[$]*	**Total Costs *[$]***
[4] Off-peak	90 MWh	$0 *[90 MWh × $0/MWh]*	$900 *[90 MWh × $10/MWh]*	**($900)**
[5] On-peak	140 MWh	$4,000 *[100 MWh × $0/MWh + 40 MWh × $100/MWh]*	$1,000 *[100 MWh × $10/MWh]*	**$3,000**
[6] Total	230 MWh	$4,000	$1,900	**$2,100**
Change in Costs and Benefits due to Storage Participation				
	Generation *[MWh]*	Production Costs *[$]*	Clean Energy Benefit *[$]*	**Total Costs *[$]***
[7]	0 MWh	($1,000)	$100	**($1,100)**

Observe that in this example, where the FCEM values clean energy at a price of $10 per MWh, the clean energy benefit is $100 greater in case 2 than in case 1, as shown in row [7]. This increase in the clean energy benefit occurs because the storage resource shifts 10 MWh of production from peaker P, which does not produce clean energy to baseload resource B, which does produce clean energy. In total, clean energy generation from baseload resource B therefore increases by 10 MWh with the participation of storage.

Thus, when we consider storage's impact on total costs, which are equal to the production costs less the clean energy benefits, the participation of storage reduces total costs by $1,100, equal to the difference between the total costs in cases 1 and 2 (rows [7], column [d]). Storage's benefit in this example is greater than that estimated in example a1 because storage not only reduces production costs by $1,000 (the same amount as in example a1), but it now also increases clean energy production by 10 MWh, which when valued at the $10 per MWh of clean energy, yields an incremental clean energy benefit of $100.

With the understanding that storage reduces total costs by $1,100, we now consider how two different FCEM eligibility criteria would impact storage's compensation, and how each relates to its contributions to reducing costs, as measured using both production costs and clean energy production.

To do so, we must first consider the impact of the FCEM on energy market prices. Recall from the earlier example that the baseload resource B that sets the clearing price during the off-peak hour has physical marginal costs of producing this energy of $0 per MWh. Under current market rules, we would expect this resource to offer into the energy market at these costs, and because it is the marginal resource in this hour, the off-peak clearing price would therefore be $0.

Under the FCEM, where the value of clean energy is assumed to be $10, we expect resource B to internalize this revenue in its energy offer price. More specifically, rather than offering at $0, its competitive offer price would decrease to –$10 per MWh because for each MWh of energy produced, it receives a clean energy certificate valued at $10.[9] As a result, in this example, the introduction of the FCEM would reduce the energy clearing price in the off-peak hour by the price of the clean energy certificates to –$10 per MWh.

Table b1.2 illustrates the total compensation to storage under two potential FCEM eligibility treatments. Under the first treatment, storage is not directly credited with certificates for clean energy production for each MWh of energy it supplies during the peak hour (illustrated in column [c]). Under the second treatment, storage is credited with clean energy certificates for this supply (column [e]). Observe that in both treatments, the storage resource is paid $100 to consume 10 MWh of energy in the off-peak hour, as the energy price in this hour is -$10 per MWh.

Table b1.2: Storage Revenues with and without Clean Energy Credits

	[a]	*[b]*	*[c] = [a] × [b]*	*[d]*	*[e] = [c] + [d]*
	Energy Clearing Price	Cleared Supply	**Storage Net Revenues without Clean Energy Credits**	Storage Clean Energy Credit Revenues	**Storage Net Revenues with Clean Energy Credits**
	[$/MWh]	*[MWh]*	***[$]***	*[$]*	***[$]***
Off-peak	-$10/MWh	-10 MWh	**$100**	$0	**$100**
On-peak	$100/MWh	10 MWh	**$1,000**	$100	**$1,100**
Total		0 MWh	**$1,100**	$100	**$1,200**

Under the first treatment, where storage is not directly credited with clean energy production, its compensation is nonetheless greater than it would be under current market rules. More specifically, its total net revenues increase by $100 from $1,000 to $1,100. This increase in revenues paid to the storage resource appropriately accounts for its contributions to clean energy production, as this $100 in additional revenues is equal to the product of the incremental clean energy facilitated by the resource (10 MWh) and the value associated with this clean energy ($10 per MWh).

[9] This reduction in offer prices is consistent with those observed for other programs for environmental attributes such as Renewable Energy Certificates (RECs) and production tax credits, where resources with low physical marginal costs lower their offer prices to reflect the value of these credits and this results in negative offer prices.

Importantly, this property will hold more generally. Storage resources will facilitate additional clean energy production when they charge during periods where the marginal resource produces clean energy, and when they discharge during periods where the marginal resource does not produce clean energy. In such cases, the energy price when the storage resource charges (that is, the price the storage resource pays to consume electricity) will decrease relative to current market rules because the marginal resource's energy offer price will be reduced to reflect the value of of clean energy certificates. However, there will not be a corresponding decrease in the price the storage resource is paid to discharge because the marginal resource in this hour is not clean, and it therefore does not reduce its energy offer price. Thus, storage's net revenues would increase because the spread between the price it is paid to supply energy, and the price it is charged to consume energy increases.

We now consider the second treatment, where storage is also credited with clean energy certificates for the energy it provides during the on-peak hour. Under this scenario, the storage resource's net revenues increase by another $100 relative to the first treatment to reflect the fact that it is awarded clean energy certificates for its 10 MWh of energy that it supplies during the on-peak hour. In this second treatment, the storage resource is effectively compensated twice for its contributions to clean energy production. It is compensated indirectly via greater energy market revenues than under current market rules because of the impact of the clean energy certificates on the energy market clearing price. Under this treatment, it is now also compensated a second time via revenues from clean energy certificates.

In this example, the storage resource helps to facilitate greater clean energy production by transferring generation from the non-clean peaker P to the clean base resource B. Yet, it is appropriately compensated for these contributions under the first treatment when it is not awarded a clean energy certificate for the energy it discharges. In fact, when it is credited with providing clean energy, as occurs in second treatment, its total compensation exceeds its contributions to the region's clean energy production because it effectively gets paid twice for its contributions to clean energy production – once via increased revenues from the energy market, and a second time via clean energy certificates.

Based on these observations, this example suggests that to awarding clean energy certificates to storage resources would not align the FCEM framework with sound market design, as they are already appropriately compensated for their clean energy contributions in the energy market. Moreover, such an approach helps to prevent consumers from "paying twice" for 10 MWh of clean energy that is produced by clean base resource B in the off-peak hour, consumed by storage resource S in this same hour, and then discharged by S in the on-peak hour.

Example b2: Storage does not increase clean energy production

The assumptions in this example mirror those from b1, with one key difference. The baseload resource is no longer a clean resource that has physical marginal costs of $0 per MWh. Rather, it is now a combined cycle resource that emits 3 units of carbon per MWh and therefore does not receive clean energy certificates. This resource has physical marginal costs of $30 per MWh. As with example b1, peaker P has physical marginal costs of $100 per MWh, where this corresponds with carbon emissions of 10 units per MWh.

Table b2.1 below shows energy awards, production costs, and clean energy benefits under cases with and without storage participation. Observe that in this example, where neither the baseload nor peaker unit produces clean energy, the total clean energy production is equal to 0 MWh under both cases, and thus there is no clean energy benefit with or without the participation of the storage resource (this is shown in column [c]).

Table b2.1: Energy Awards, Production Costs, and Clean Energy Benefits

	[a]	[b]	[c]	[d] = [b] - [c]
Case 1: No Storage Participation				
	Generation [MWh]	Production Costs [$]	Clean Energy Benefit [$]	Total Costs [$]
[1] Off-peak	80 MWh	$2,400	$0	$2,400
[2] On-peak	150 MWh	$8,000	$0	$8,000
[3] Total	230 MWh	$10,400	$0	$10,400
Case 2: Storage Participation				
	Generation [MWh]	Production Costs [$]	Clean Energy Benefit [$]	Total Costs [$]
[4] Off-peak	90 MWh	$2,700	$0	$2,700
[5] On-peak	140 MWh	$7,000	$0	$7,000
[6] Total	230 MWh	$9,700	$0	$9,700
Change in Costs and Benefits due to Storage Participation				
	Generation [MWh]	Production Costs [$]	Clean Energy Benefit [$]	Total Costs [$]
[7]	0 MWh	($700)	$0	($700)

In this example, while storage does not impact the clean energy benefit (which is $0 across all hours), it does reduce production costs by $700 by shifting energy production from the higher cost peaker to the lower cost baseload unit (shown in row [7], column [b]).

Table b2.2 considers the storage resource's total compensation under these same two eligibility treatments, where the first treatment does not credit storage with clean energy production for each MWh of energy it supplies during the peak hour (column [c]), and the second treatment does (column [e]).

Table b2.2: Storage Revenues with and without Clean Energy Certificates

	[a]	[b]	[c] = [a] × [b]	[d]	[e] = [c] + [d]
	Energy Clearing Price	Cleared Supply	Revenues without Clean Energy Certificates	Storage Clean Energy Certificate Revenues	Storage Net Revenues with Clean Energy Certificates
	[$/MWh]	[MWh]	[$]	[$]	[$]
Off-peak	$30/MWh	-10 MWh	($300)	$0	($300)
On-peak	$100/MWh	10 MWh	$1,000	$100	$1,100
Total		0 MWh	$700	$100	$800

As occurred with the first treatment in example b1, if storage is not credited with delivering clean energy, its total net revenues are equal to the benefits it provides when accounting for both production costs and clean energy. This compensation is equal to $700, the amount by which it reduces total costs (in this case, just through reduced production costs), as shown by comparing total costs in cases 1 and 2 in row [7] of Table b2.1. Importantly, under a clean energy framework, while the storage resource reduces carbon emissions by shifting production from peaker P, which emits 10 units of carbon per MWh of energy produced to baseload resource B, which only emits 3 MWh, it receives no incremental revenues for these contributions because these contributions do not increase clean energy production. As explained later in example c2, a carbon price would allow the storage resource to be compensated for these carbon emisison reduction contributions.

However, if storage is also credited with delivering clean energy as occurs under the second eligibility treatment, it would instead receive total compensation of $800, where this additional $100 corresponds with the value of these certificates. This value exceeds the benefits that it provides, as measured using the FCEM framework which values clean energy production at $10 per MWh, but does not directly value carbon emissions reductions. More specifically, it compensates the storage resource as if it increased the region's clean energy output by 10 MWh, even though the storage resource's participation has no impact on clean energy production.

This example again illustrates an instance where storage is appropriately compensated for its contributions to reducing system production costs and clean energy production when it is not credited with providing clean energy. If it was credited with providing clean energy, this would result in the storage resource receiving compensation that exceeds its contributions to system efficiency, as it would incorrectly indicate that storage's participation increased clean energy production.

Awarding clean energy certificates to storage could undermine FCEM's effectiveness in increasing clean energy production

As examples b1 and b2 illustrate, directly crediting storage resources with clean energy certificates would lead such resources to be compensated at a level that exceeds their contributions to clean energy production. By overcompensating storage resources when they cycle, this approach would create financial incentives for storage resources to charge and discharge (cycle) in order to receive clean energy certificates, including instances when this cycling does not benefit the system, as measured by production costs, clean energy production, or carbon emissions reductions.[10]

Additionally, by overcompensating storage resources, this approach may undermine the FCEM's ability to increase actual clean energy production, as this increased cycling by storage resources would reduce the number of certificates available for other types of clean generation. While states may adjust clean energy targets upwards to account for storage activity, forecasting the quantity of clean energy certificates

[10] Taken to its extreme, if storage receives clean energy certificates for its energy supplied, a facility with two adjacently-located storage assets could be simultaneously charging one while discharging the other. Because this energy is simply being transferred back and forth between the facilities, it provides no value to the system. However, the asset could profit from the clean energy certificates it is awarded.

awarded to storage resources would likely prove challenging and may therefore increase uncertainty about the states' ability to achieve their desired environmental outcomes in a cost-effective manner.

As illustrated in examples b1 and b2, not awarding clean energy certificates to storage resources compensates storage resources for their contributions to reducing production costs and increasing clean energy production. By not compensating storage resources above their contributions, it avoids creating these perverse incentives for storage resources to cycle to receive clean energy certificates even when this act does not reduce system production costs, increase clean energy production, or reduce carbon emissions.

c. Storage's compensation under a net carbon price

This section now considers storage's contributions and compensation under a net carbon pricing framework. It uses the same pair of numerical examples as are presented in section b, where, rather than employing an FCEM, there is now a carbon price of $1 per unit of carbon emitted. In this example, when the baseload resource is a clean resource, as occurs in example c1, it produces no carbon emissions and thus does not increase its offer price to reflect a cost for emitting carbon.

The peaker resource is a combustion turbine generator that emits 10 units of carbon per MWh of energy produced. To account for the cost associated with these emissions, this unit adds a $10 per MWh to its energy offer.

Similar to the discussion of the FCEM framework above, these examples assume that any new revenue that is collected via a net carbon price is rebated to RTLO, where this distribution does not extend to storage resources.[11]

Example c1: Storage shifts generation to non-emitting resources

This example mirrors examples a1 and b1, where the base resource B is clean and does not emit carbon. Rather than including a clean energy benefit as is consistent with an FCEM construct, this example considers the costs associated with carbon emissions in a manner consistent with a net carbon pricing framework, which effectively assigns a cost to carbon emissions. This results in carbon costs being added to the production costs to produce total costs, whereas in the earlier examples the clean energy benefits were subtracted from the production costs.

As previously, case 1 reflects the total system costs when the storage resource does not participate, and case 2 illustrates the costs when the storage resource does participate.

[11] While the memo does not explicitly consider approaches that would rebate carbon revenues to storage, such approaches appear to be less effective in compensating storage for their contributions to carbon reductions.

Table c1.1: Energy Awards, Production Costs, and Carbon Emissions Costs					
		[a]	*[b]*	*[c]*	*[d] = [b] + [c]*
Case 1: No Storage Participation					
		Generation *[MWh]*	Production Costs *[$]*	Carbon Emissions Costs *[$]*	Total Costs *[$]*
[1]	Off-peak	80 MWh	$0 *[80 MWh × $0/MWh]*	$0 *[80 MWh × $0/MWh]*	$0
[2]	On-peak	150 MWh	$5,000 *[100 MWh × $0/MWh + 50 MWh × $100/MWh]*	$500 *[100 MWh × $0/MWh + 50 MWh × $10/MWh]*	$5,500
[3]	Total	230 MWh	$5,000	$500	$5,500
Case 2: Storage Participation					
		Generation *[MWh]*	Production Costs *[$]*	Carbon Emissions Costs *[$]*	Total Costs *[$]*
[4]	Off-peak	90 MWh	$0 *[90 MWh × $0/MWh]*	$0 *[90 MWh × $0/MWh]*	$0
[5]	On-peak	140 MWh	$4,000 *[100 MWh × $0/MWh + 40 MWh × $100/MWh]*	$400 *[100 MWh × $0/MWh + 40 MWh × $10/MWh]*	$4,400
[6]	Total	230 MWh	$4,000	$400	$4,400
Change in Costs due to Storage Participation					
		Generation *[MWh]*	Production Costs *[$]*	Carbon Emissions Costs *[$]*	Total Costs *[$]*
[7]		0 MWh	($1,000)	($100)	($1,100)

As can be seen by comparing total cost between cases (row [7], column [d]), the participation of the storage resource reduces total costs by $1,100, where $1,000 of this cost reduction comes via lower production costs (consistent with examples a1 and b1 and shown in column [b]), and the remaining $100 comes via reduced carbon emissions (as illustrated in column [c], 10 MWh of generation that produce 100 units of carbon at total cost of $100 are replaced by non-emitting generation).

We now consider storage resource S's revenues under such a framework which depend on the energy prices in the off- and on-peak hours. Importantly, the baseload resource B will offer its energy at a price of $0, to reflect the fact that it has physical marginal costs of $0, and it incurs no incremental costs associated with the carbon price. Thus, in the off-peak hour, the energy price will be $0 per MWh. The peaker P will set the energy price at $110 per MWh, reflecting its physical marginal costs of $100 and a carbon adder of $10 per MWh.

These revenues are shown in Table c1.2, where storage resource S is appropriately compensated for the $1,100 reduction in costs it provides, as this revenue accounts for both the decrease in production costs, and the value associated with storage resource S's role in reducing carbon emissions. In this example, the introduction of a carbon price has no impact on storage's costs to buying energy during the off-peak hour relative to current market rules because the marginal resource (clean resource B) does not emit carbon.

However, the carbon price increases its revenues during the on-peak hour because the marginal resource, peaker P, does emit carbon and thus increases its energy offer price. As a result, its total compensation accounts for its contributions to reducing carbon emissions, as the net carbon price leads it to receive higher revenues when discharging without impacting its costs to charge.

Table c1.2: Storage Revenues under Net Carbon Pricing			
	[a]	*[b]*	*[c] = [a] × [b]*
	Energy Clearing Price	Cleared Supply	Storage Net Revenues without Clean Energy Credits
	[$/MWh]	*[MWh]*	*[$]*
Off-peak	$0/MWh	-10 MWh	$0
On-peak	$110/MWh	10 MWh	$1,100
Total		0 MWh	$1,100

Thus, a net carbon price leads the marginal carbon emissions rate to be incorporated in the energy price in the hours when storage is charging and discharging. This leads the storage resource's profits to include its marginal contributions to reducing carbon emissions.

Example c2: Storage shifts generation to lower-emitting resources

Finally, we consider the example where the base resource B is no longer clean, and instead is a combined cycle resource that emits 3 units of carbon per MWh of energy produced. As a result, in this example, base resource B adds $3 per MWh to its energy offer to account for the cost associated with its carbon emissions under this net carbon pricing framework, resulting in an energy offer of $33 per MWh.

This example is analogous to example b2, except that we now assume a carbon price is in place rather than an FCEM. The impact on total costs, including those associated with carbon emissions, is included in Table c2.1.

	[a]	[b]	[c]	[d] = [b] + [c]
Case 1: No Storage				
	Generation [MWh]	Production Costs [$]	Carbon Emissions Costs [$]	Total Costs [$]
[1] Off-peak	80 MWh	$2,400	$240	$2,640
[2] On-peak	150 MWh	$8,000	$800	$8,800
[3] Total	230 MWh	$10,400	$1,040	$11,440
Case 2: Storage				
	Generation [MWh]	Production Costs [$]	Carbon Emissions Costs [$]	Total Costs [$]
[4] Off-peak	90 MWh	$2,700	$270	$2,970
[5] On-peak	140 MWh	$7,000	$700	$7,700
[6] Total	230 MWh	$9,700	$970	$10,670
Change in Costs due to Storage Participation				
	Generation [MWh]	Production Costs [$]	Carbon Emissions Costs [$]	Total Costs [$]
[7]	0 MWh	($700)	($70)	($770)

As shown in row [7], the participation of the storage resource in this example reduces costs by $770, where $700 of this cost reduction stems from decreased production costs, and the remaining $70 comes from a decrease in carbon emissions.

As illustrated in table c2.2, a carbon price framework would appropriately compensate the storage resource for these contributions, as its net revenues are equal to this reduction in total costs. In this example, the storage resource's costs associated with consuming energy during the off-peak hour increase relative to current market rules because the marginal resource increases its offer price by $3 per MWh to reflect the costs associated with its carbon emissions. However, this increase in costs is more than offset by an increase in revenues during the on-peak hour, where the price increases by $10 per MWh, thus indicating that storage is shifting energy production from a higher emitting resource (peaker P) to a lower emitting resource (baseload B).

Table c2.2: Storage Revenues under Net Carbon Pricing			
	[a]	[b]	[c] = [a] × [b]
	Energy Clearing Price [$/MWh]	Cleared Supply [MWh]	Storage Net Revenues without Clean Energy Credits [$]
Off-peak	$33/MWh	-10 MWh	-$330
On-peak	$110/MWh	10 MWh	$1,100
Total		0 MWh	$770

Importantly, the carbon price framework more directly connects compensation to carbon emissions, rather than employing a binary eligibility criteria to determine what technologies are clean. This allows the storage resource (and other lower emitting resources that are not characterized as clean) to be compensated for their contributions to reducing carbon emissions, even if they do not increase the quantity of clean energy produced. This can be seen in the above example in which the net carbon pricing framework leads the storage resource to receive $70 for its contribution to reducing carbon emissions.

3. Conclusion

The memorandum highlights how storage contributes to clean energy production or reduction in carbon emissions by shifting energy production from higher emitting resources during on-peak hours to lower- or non-emitting resources during off-peak hours. It then considers a series of examples to assess how storage are appropriately compensated for these contributions under FCEM and net carbon pricing frameworks using a series of numerical examples.

Examples b1 and b2 find that storage resources would be appropriately compensated for their contributions to reducing production costs and increasing clean energy production under an FCEM framework if they are not awarded clean energy certificates. This outcome occurs because the energy market revenues storage receives would reflect its contribution to clean energy production because the price it pays to consume electricity and that it receives for discharging electricity both account for the clean energy contributions of the marginal resource.

In fact, if energy supply provided by storage resources was awarded clean energy certificates under an FCEM framework, storage's compensation would exceed its clean energy contribution. This outcome would adversely impact the region's ability to cost-effectively meet its environmental objectives via an FCEM and create incentives for storage resources to cycle even when doing so did not reduce production costs or increase clean energy production. Thus, awarding storage resources clean energy certificates in the FCEM framework is inconsistent with sound market design.

The memorandum also shows that a net carbon pricing framework is well situated to appropriately compensate storage resources for their contributions to reducing carbon emissions. Under this framework, both the price storage pays to consume electricity and the price it is paid to discharge electricity include carbon costs associated with the emissions rate of the marginal resource. Thus, if storage is shifting energy production from a higher emitting resource to a lower emitting resource, the higher carbon adder will be included in the energy price it is paid, and the lower carbon adder will be embedded in the energy price it is charged. This outcome is illustrated in Examples c1 and c2.

The examples also illustrate instances where different pathways the region is evaluating, an FCEM and net carbon pricing, produce dissimilar outcomes for storage resources based on the new product definitions. More specifically, examples b2 and c2 identify an instance where storage's participation has no impact on clean energy production, but it would reduce carbon emissions by transferring generation from a higher emitting resource to lower emitting (but not a carbon-free) resource. Storage would be compensated for this contribution under a net carbon pricing framework, as its contributions are consistent with the environmental attribute targeted – carbon emissions reduction. However, under an FCEM approach it would not be compensated for this contribution because its participation does not impact clean energy production.

ANALYSIS GROUP

Pathways Study

Evaluation and Impact Analysis

Todd Schatzki
Principal

April 15, 2021

Agenda

- Overview of Assignment and Approach
- Model Structure and Mechanics
- Inputs, Assumptions, and Scenarios Evaluated

Overview of Assignment and Approach

Assignment

- Analysis Group (AG) has been asked to evaluate proposed alternative **approaches** to a more decarbonized future grid and compare them to continuation of the current rules ("Status Quo"). Thus, we will evaluate three approaches, or cases:
  - Status Quo
  - Forward Clean Energy Market (FCEM) / Integrated Clean Capacity Market (ICCM)
  - Net Carbon Pricing
- Our work will include **quantitative and qualitative analysis** of each approach with the goal of identifying important differences between them
  - We will focus on factors that are most relevant to differentiating between these approaches, such as environmental and economic outcomes, and how each approach incents desired resource mix changes
  - Quantitative analysis will aim to capture key differences in environmental and economic outcomes, but, in practice, will not capture all differences
  - Qualitative analysis will identify and assess differences between approaches that are not captured by the quantitative analysis

Assignment

- The **quantitative modeling** of each approach based on cases designed to illustrate key differences between each approach:
  - Compare approaches under common **"central"** assumptions and also consider alternative scenarios reflecting different common assumptions and particular design choices
  - Illustrate the mechanisms by which each approach incents changes in investment or behavior that result in different market outcomes, drawing on examples from model runs
  - Quantitative work will focus on outcomes most relevant to understanding the choice regulatory approach to incenting desired resource mix changes – as a result, certain factors important to future grid outcomes, such as reliability outcomes, will be less of a focus
- Our work is intended to inform stakeholders about the proposed approaches

Quantitative Analysis Approach

- Evaluate outcomes of each approach starting with a central case
  - Each approach will be analyzed assuming the same market conditions and emission targets
  - Intention is to analyze using a common set of assumptions so that differences in outcomes across scenarios reflect differences in approaches, not other factors
- Evaluate market outcomes under additional scenarios
  - Some scenarios will test sensitivity to different assumptions about market conditions, policy targets and other factors common to all approaches
  - Other scenarios will test the sensitivity of outcomes to design decisions for particular approaches
- Modeling inputs, assumptions, and scenarios will be informed by discussion with and feedback from stakeholders
  - Where feasible and sensible, we will align assumptions with the Future Grid Reliability Study (FGRS)

Overview of Schedule and Process

- Study will proceed in stages to:
  - Align AG, ISO and stakeholders on study objectives
  - Gather stakeholder input on design of approaches, input assumptions and desired scenarios
  - Provide preliminary results to obtain stakeholder feedback
  - Develop final study findings, including final report
- Process will proceed according to the following proposed schedule:
  - **May-June, 2021** Discuss approach designs, model inputs, and scenarios
  - **July-August, 2021** Simulation modeling (potential for additional stakeholder discussion of inputs)
  - **October, 2021** Preliminary results
  - **November, 2021** Detailed central case results
  - **December, 2021** Preliminary scenario results
  - **February, 2021** Report delivered

Model Structure and Mechanics

Overview of Modeling Approach: Model Components

- Analysis will use a multi-module model to simulate the New England electricity markets:
  - Energy markets, including proposed net carbon pricing
  - Capacity markets
  - Proposed clean energy market frameworks
- Models will reflect current market structures and rules, and not include potential modifications that may occur in the future
  - Application of MOPR will be determined
- Model follows two steps:
  1. Determine the future resource mix using a "capacity expansion" model
  2. Analyze outcomes in energy market and capacity market, reflecting approach taken to meeting decarbonization target (status quo, FCEM or net carbon pricing)

Overview of Modeling Approach: Model Components

Inputs and Assumptions

- Existing resource going-forward costs
- Costs of new entry
- Variable O&M
- Heat rates
- Load
- Etc.

(Described in further detail in next section)

Market Simulation

Capacity Expansion

Resource entry/exit

- Embedded EAS market
- Resource adequacy requirements
- Policy targets

Energy & Ancillary Service (EAS) Market

- Energy
- Operating reserves
- Carbon pricing

Net EAS Revenues

Forward Capacity Market (FCM, with and without Integrated FCEM)

- Based on going-forward costs, given net EAS revenues
- Resource adequacy requirements
- FCEM requirements

Results

EAS Market

- Payments
- Production costs
- LMPs
- Carbon prices
- Emissions
- Generation mix

Forward Market

- Capacity prices
- CEC prices
- CEC payments

Common Inputs and Assumptions

- Common set of central case assumptions across all approaches
  - Regional carbon emission target
  - Hourly load shapes, reflecting assumed electrification of transportation and heating
  - Existing generation portfolio (and their operating parameters and costs)
  - Renewable generation profiles (reflecting weather patterns)
  - Fuel and non-carbon emissions prices
  - Existing state policies, including RPS
- Different approaches to achieve regional carbon emission target beyond central case state policies:
  - Status quo – Incremental state policies to meet target, with long-term contracts
  - FCEM / ICCM – Procurement of Clean Energy Certificates (CEC) to meet regional target
  - Net Carbon Pricing – Set carbon price to meet regional target
- Market footprint will include ISO-NE and NYISO, with supply curve for HQ

Proposed Study Outcomes

- This study will focus on differences in outcomes across approaches to give insight into how outcomes may differ under each approach
- Potential quantitative outcomes include:
  - Customer payments
  - Total production costs
  - Wholesale energy and reserve prices (LMPs)
  - Capacity prices
  - Environmental prices (carbon, CEC)
  - Emissions
  - Resource mix, by technology type (MW, MWh)
- Qualitative analysis
  - Quantitative analysis will capture some but not all differences in approaches, while qualitative analysis will aim to identify and evaluate other consequential differences in outcomes across approaches

Inputs, Assumptions, and Scenarios Analyzed

Approach to Inputs and Assumptions

- The model requires many inputs and assumptions, some involving substantial detail
  - Where possible and sensible, we will align assumptions with the FGRS
  - Other assumptions will be developed with the aim of capturing future market and system conditions to provide the most suitable basis for comparing approaches
- Central case inputs will be developed first, and scenario analysis will be performed based on changes to the central case assumptions
  - Scenario analysis will generally reflect changes to either approach design or market conditions
- The following slides provides an overview of key assumptions and inputs, and provide preliminary thinking on assumptions in certain areas
- We welcome stakeholder feedback on inputs and assumptions, and final inputs and assumptions will reflect feedback received from stakeholders

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Modeling Inputs and Assumptions

- Study Parameters
  - Year(s) studied
  - Regional carbon target (applicable to each approach)
- Electricity Markets
  - Current resource mix, known additions/retirements
  - Fuel prices
  - RGGI and non-carbon emissions pricing
  - Import/export assumptions
  - Load shapes (hourly)
    - Electrification (transportation, home heating) assumptions
    - Energy efficiency assumptions
  - Renewable hourly resource profiles (e.g., hydro, onshore wind, offshore wind, solar)
  - Storage resource specifications
- Capacity Markets
  - Going forward costs (fixed operating costs for existing resources)
  - Technology-specific cost of new entry (CONE) (amortized capital and fixed operating costs)
  - MOPR (i.e., will MOPR be applied or not applied)

Approach Inputs and Assumptions

- State Policies
  - Existing policies to be assumed across cases, such as RPS
- Status Quo
  - Incremental policies (e.g., incremental RPS) needed to meet assumed regional carbon target and their specific implications for technology mix and location
  - Current and future long-term contracts (implications for costs)
- Net Carbon Pricing
  - Carbon price (to achieve regional carbon target)
  - Leakage rules
- FCEM / ICCM
  - Design:
    - Integration of FCEM into FCM
    - Eligibility of resources for CECs
    - Static CECs (potential for dynamic scenario)
  - Inputs:
    - State-level demand for CECs (to achieve the regional carbon target)
    - Resource-level CEC offer quantity
  - Allocation of costs and settlement:
    - Non-compliance penalty rates
    - Banking of CECs across years

Modeling Year(s) Studied

- Preliminary thinking to use target year of 2040
  - Consistent with FGRS
  - Capacity expansion model will provide resource mix for intermediate years
  - Potential to include full results for other years or certain policies/scenarios, particularly if we determine that findings differ for intermediate years
- Analysis will assume a ‘weather normal’ year
  - Preliminary thinking is to use 2019, modified to reflect future changes

State Policies

- Many current states policies:
  - RPS - Current RPS targets reflect both legislation and executive orders
  - Clean Energy Standard (CES) – In effect, expands to include other non-emitting sources
  - Procurements – zero carbon resources (CT), off-shore wind (MA, RI), etc.
  - Others – Clean Peak Standard (MA), cap and net metering (behind the meter changes in load), trade (MA), solar targets and policies (e.g., rebates – CT, SMART – MA)
- Policies vary in statutory mandate:
  - Some policies explicitly specified in statute
  - Some policies implemented to achieve statutory target
  - Some policies implemented via executive order

Current State Policies

Aggregate, Regional Impact of Various State Policies

- Existing policies vary across states in terms of quantity of targeted clean/renewable energy (and eligible technologies)

	2040 Requirement Quantity (% of Load)	
State	**RPS Only**	**RPS + CES + Other**
Connecticut	48%	100%
Maine	80%	80%
Massachusetts	57%	74%
New Hampshire	25%	25%
Rhode Island	39%	100%
Vermont	75%	75%
Total (load weighted)	54%	77%

Note: Estimates by AG based on review of state legislative mandates. "CES + Other" includes Massachusetts Clean Energy Standard, Massachusetts Alternative Energy Portfolio Standard, and Executive Orders in both Connecticut and Rhode Island. Load weighting based on ISO-NE's 2029 load forecast, net of behind the meter solar and energy efficiency.

State Policies

- State policies assumed with each approach need to reflect a reasonable mix of existing policies, with alternative approaches being studied – i.e., status quo, FCEM / ICCM, net carbon pricing – achieving incremental carbon reductions to achieve regional carbon target
  - If central case policies achieve too many reductions, analysis of approaches will not yield useful information for assessment
- Potential options
  1. Include only outcomes of existing procurements and planned procurement (i.e., no RPS)
  2. Include a scaled down version of current RPS
  3. Current RPS (e.g., as represented on prior slide)
- Preliminary observations
  - #1 (existing procurements) provides the opportunity to most clearly differentiate between the three approaches
  - #2 (scaled-down RPS) may balance desire to account for existing state policies and allow the study to provide useful information to evaluate the approaches
  - #3 (current RPS) may offer too little incremental reductions to meaningfully evaluate the approaches
- We look forward to input from stakeholders on a sensible mix of assumptions

Potential Scenarios

- Across approaches:
  - Alternative regional carbon target
  - Alternative levelized costs of new entry for renewable resources (given uncertainty in cost trajectory)
  - Alternative load forecasts (e.g., different levels of electrification of heating, transportation)
  - Alternative natural gas price projection
  - Remove existing (central case) state policies
  - Alternative MOPR assumption (removal/inclusion depending on central case assumption)
- Status Quo
  - Alternative costs of long-term renewable contract procurement
- FCEM / ICCM
  - "Dynamic" pricing (may be studied in an abridged fashion)
  - Alternative penalty rate
- Net Carbon Pricing
  - Leakage rules

- We look forward to input from stakeholders on a sensible mix of scenarios
  - Timely input will increase likelihood that model is capable of evaluating or can reasonably evaluate the desired scenario

Next Steps

- May
  - Review feedback from stakeholders
  - Provide preliminary proposal for assumptions and inputs
- June
  - Review any additional feedback from stakeholders
  - Present finalized assumptions and inputs

ANALYSIS GROUP

Contact

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Memorandum

April 5, 2021

To: ISO New England, NEPOOL

From: Pete Fuller & David O'Connor, on behalf of NRG Energy and other stakeholders

Re: Future Grid Pathways Study – Further Input

In response to the ISO-NE presentation at the March 18 Pathways meeting, we offer this memo to provide additional input and feedback regarding the structure and assumptions for the Pathways study of the Forward Clean Energy Market (FCEM) and Net Carbon Pricing. The content here was drafted by consultants for NRG Energy, Inc. based on discussions and collaboration with a number of other NEPOOL market participants. We appreciate the opportunity to continue to engage with the ISO, NESCOE and other stakeholders and provide our perspectives on the important design parameters for incorporating the New England States' clean energy and decarbonization objectives into the ISO competitive markets, and we look forward to continued collaboration on these issues.

Modeling structure – Business as Usual

We are supportive of the ISO's stated intent to evaluate the Integrated Clean Capacity Market (ICCM)[1] and Net Carbon Pricing (Net-C) market designs. In order to provide context, however, those designs need to be compared to a business as usual (BAU) case. While there have been several passing mentions of a BAU comparison case, we believe more attention needs to be placed on developing the assumptions and parameters of the BAU scenario. Some particular comments and questions include:

- We start with the assumption that all of the cases being evaluated should be designed to meet the same overall level of emissions and reliability standards, such as 'net zero by 2050,' and that each scenario needs to be measured against the same level of clean energy or decarbonization achievement. Our hypothesis is that a market-based approach such as ICCM could achieve more emission reductions more quickly and at lower cost than the contract-based approach that States have traditionally relied on to procure clean energy resources. Both the BAU and the market-based cases need to be constructed in a way that enables us to test that hypothesis.
- How will the model capture the dynamics and the comparative costs and risks of an episodic RFP structure driven by legislative cycles compared to a regular annual procurement of a common product through a competitive wholesale market for clean energy?

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[1] We understand that although evaluation of the two approaches is still on-going, ISO has preliminarily determined that "the joint clearing of capacity and clean energy in a single auction [i.e., ICCM] is theoretically feasible ..." (ISO-NE, Developing a Straw FCEM Framework, March 11, 2021, p. 9 (p. 56 at https://www.iso-ne.com/static-assets/documents/2021/03/npc-fg-20210318-composite.pdf). Consistent with the majority of stakeholder feedback that appears to favor the ICCM approach, we use 'ICCM' throughout this memo with the understanding that the term also includes FCEM to the extent the integrated, co-optimized approach is found to be unworkable for some reason.

- Presumably the BAU case should be constructed assuming completion of the technology-specific contracts contained in current statutes, but what should be assumed for procurements in the longer term? Would State procurements continue to target specific technologies or shift to a more technology-neutral and vintage neutral approach? What other State interventions should be assumed? How should 20-year contracts and their costs and cash-flows be modeled? What role should the Alternate Compliance Payment (ACP) mechanisms play in the model?
- Should the model assume FCM product definition and obligations remain unchanged? Should it take into account ELCC or other likely market changes?
- How should the model account for requirements for balancing resources and additional ancillary services?
- How will the BAU scenario treat existing renewable energy resources and other non-emitting sources? In particular, how will the BAU scenario treat expiring contracts? Should we assume States authorize future procurements for which existing resources are eligible? What should be assumed about continued operation of existing non-emitting resources that do not have or do not receive contracts? What technologies should be assumed to replace retiring non-emitting resources, and under what business model?

<u>Participation in FCEM by Resources with State-backed Contracts</u>
One of the 'facts on the ground' that would have to be incorporated into the implementation of an ICCM is the existence of the substantial contracts for clean energy that exist today, or that will exist by the time the region can proceed with ICCM implementation. As in our previous materials[2] we continue to recommend that the model consider three scenarios.

- Scenario 1 – assume contracted resources are external and do not participate in ICCM. This scenario has the downside of bifurcating the clean energy 'market' and understating the region's full clean energy needs in the ICCM, though that effect would presumably decrease as existing contracts reach their terminations and the demand would shift into the ICCM.
- Scenario 2 – assume the supply and demand associated with contracted resources participate in ICCM with non-FCEM contract revenues subject to MOPR. This scenario assumes the continued existence of a MOPR and would estimate the ICCM offer prices for contracted resources based on their total estimated costs less the estimated market value of energy and ancillary services provided by the resources. Any modeled clean energy credit revenues received by these resources under FCEM or ICCM as well as energy and ancillary service earned in the ISO markets would be assumed to be passed through to the utility customers responsible for the existing contract payments. Modeled capacity revenues would be assumed to flow to the project owner, based on our understanding that existing clean energy contracts rarely, if ever, include capacity.
- Scenario 3 - assume contracted resource supply and demand participate in ICCM with no MOPR applied, and with all non-FCM market revenues flowed through to the customers responsible for the contract payments. This scenario would provide a comparison to Scenario

[2] Fuller & O'Connor on behalf of NRG Energy and Others, FCEM in New England: Feedback on ISO-NE Questions, March 18, 2021 (pp. 79-101 at https://www.iso-ne.com/static-assets/documents/2021/03/npc-fg-20210318-composite.pdf).

2 and an indication of the importance (or not) of applying MOPR to clean energy resources entering the capacity market and also supported by contracts.

Establishing State Clean Energy Demand in ICCM

The process for establishing clean energy demand for modeling purposes will vary by State, just as it will for actual implementation. The primary reason for this is the variation in how each State has defined its own emission reduction or clean energy goals. For example, Massachusetts' new climate law has set a goal of economy-wide net-zero emissions by 2050, with interim targets for sub-sectors of the economy. Connecticut's latest statutory goal is to reduce greenhouse emissions by 45% from 2001 levels by 2030 and 80% by 2050, while Rhode Island has set a goal of using 100% renewable energy by 2030.

In each case, some or all of the following steps may be required to 'translate' from the State's goal to a quantity of clean energy requirement that can be modeled in the ICCM. Starting with the State goals as contained in statute, Executive Order, etc., first translate as needed to the percent emission reductions needed from the energy sector. Apply that percentage to the relevant baseline year emissions to estimate total allowable tons in the target year. Create a straight-line path[3] for intervening years if necessary. Estimate total electricity demand in the study year, which should take into account forecasts of electrification of heating and transportation as well as other load growth dynamics.[4] Assuming natural gas as the supply source for all non-emitting MWh, calculate the amount of MWh that must come from non-emitting sources in the study year to meet the allowable emissions limit.

One important assumption regarding State clean energy demand relates to the level of supply in the market. Both for modeling and implementation purposes, it will be critically important for the demand quantity to be sufficiently large so that it exceeds the quantity of supply assumed to offer as price-takers. Existing clean energy resources subject to long-term contracts and other existing, uncontracted clean energy resources can be expected to offer into ICCM at low, or even zero, prices due to either the sunk nature of their investments or their contract revenue. If the aggregate demand for clean energy does not exceed the quantity of price-taking supply, the market (or the model) will not reveal a meaningful marginal cost of meeting the States' clean energy goals and clean energy market signals will fail to attract new investment in non-emitting resources.

Rationable Offers

In the original formulation of ICCM, we had posited a need to have offers be non-rationable as a means to ensure that resources offering both clean energy and capacity would not be at risk of clearing for one product but not the other. ISO's ICCM Scoping Memo[5] suggests an offer structure that would keep the clean energy and capacity offers linked, avoiding the problem of taking on an obligation for one product but not the other. We support continued investigation and development of ISO's proposal to model rationable offers based on MW and MWh/MW offered, the key being that a resource offering both products will not clear one without clearing the other. In evaluating the model results, it will be necessary to examine, and possibly reject, cases in which either the $/MW or $/MWh

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[3] We assume a straight-line approach would be most appropriate unless the relevant State requirement specifies some other trajectory.

[4] As noted in our March 18 materials, the demand assumptions being used for the Future Grid Reliability Study appear to be a good starting point for this modeling effort.

[5] Pp. 57-61 at https://www.iso-ne.com/static-assets/documents/2021/03/npc-fg-20210318-composite.pdf

price is zero/very low, or in which only a *de minimis* portion of one or more resources clears the market. Even if the total revenue to be earned by an ICCM resource from the base capacity and clean energy credit prices would satisfy the total offer cost requirements of the resource, it may be unattractive to hold an obligation if there is a high risk of net losses based on the performance requirements associated with the two products. Likewise, participants will need some means to ensure that they clear a sufficient share of their resource to justify operating the full resource.

Dynamic Credits and Storage

As described in our earlier feedback and out of expedience to get the modeling started, we continue to recommend approaching the initial modeling effort with static (i.e., non-time-varying) clean energy credits. That said, we strongly support parallel efforts to better understand how dynamic credits could work, for example, understanding hourly dynamics, patterns and relationships of emission rates, and correlations to demand, price or other observable factors. We would then expect to develop one or more frameworks for implementing dynamic credits as part of ICCM based on this new understanding.

We had previously suggested making energy storage resources eligible for ICCM clean energy credits as long as they could demonstrate that they used charging energy from eligible clean energy resources. ISO-NE indicated at the March 18 meeting a continued openness to exploring avenues for compensating storage resources for their ability to facilitate and enhance the integration of renewable energy into the system, suggesting that energy price volatility and possibly dynamic credits as the most 'sensible' mechanisms through which storage could monetize its value. We acknowledge that making energy storage eligible for clean energy credits requires careful avoidance of double-counting issues and we are likewise open to exploring how the markets can reveal and compensate the operational and emission reduction value of energy storage, recognizing that some of that value may be identified in studies beyond the scope of this Pathways effort, such as the Future Grid Reliability Study.

ICCM Credits vs. RECs

ISO's memo on a Straw FCEM Framework suggested three approaches for how the new clean energy credits would interact with existing State programs. Our observation is that all of these approaches appear to put a lot of emphasis on modeling existing REC programs, which is likely to be complex and appears to be somewhat outside the scope of the Pathways modeling effort. As an alternative we continue to recommend a simpler approach that only assesses the impact of revenues from REC markets on ICCM modeled results. One scenario would assume that resources producing FCEM/ICCM credits do not receive any revenues from REC trading (this is potentially equivalent to Approaches 2 and 3 as suggested by ISO). In the other scenario, assume a market price (eg, $40/MWh for Class I and perhaps $300/MWh for Solar RECs) which would act to reduce the offered prices of eligible resources in FCEM/ICCM.

Vistra Corp. (Vistra) appreciates ISO-NE's efforts to model potential market designs for the region's clean energy transition. Vistra is very supportive of these efforts. Vistra has four specific comments it would like to provide as ISO-NE contemplates how it will model the potential market designs.

FCEM

1. **Product Definition**. Vistra recognizes that the states and many stakeholders (at least given current information) prefer the FCEM design as the path forward for incorporating decarbonization efforts into the wholesale markets. To be clear, while Vistra continues to prefer carbon pricing as the best path forward for the region to achieve needed decarbonization in a manner that preserves the many benefits of competitive markets, Vistra is open to a well-designed FCEM as a potential alternative market design. ISO-NE has proposed to model the FCEM assuming that market participants would procure a single clean energy product. Vistra believes that an FCEM that is designed for the procurement of a single, resource-neutral, clean energy product is the right design for maximizing the competitive benefits that must be achieved. To date, however, it appears that many stakeholders anticipate an FCEM design that allows purchasers to buy multiple products to reflect the individual needs of specific states, municipals, or even private parties. It is critical that ISO-NE's modelling efforts appropriately account for proposed market design details that most closely align with the actual market design preferences of stakeholders. Presenting results for the most efficient version of the FCEM rather than the version of FCEM some stakeholders favor could distort the understanding of the relative merit of the FCEM. Thus, Vistra urges ISO-NE to model FCEM by assuming multiple products to account for individual state (or other purchasing party) preferences in terms of both product type and location. If ISO believes that an FCEM simultaneously solving for a variety of different products is not feasible, that should be made clear now, not later.
2. **Gradation for Lower Emitting Resources**. The proposed FCEM design assumes that only zero emitting resources are awarded clean energy certificates. Vistra believes that lower emitting resources, such as efficient natural-gas fired resources, will be critical in facilitating the clean energy transmission, and thus these lower emitting resources should be valued for their contribution to decarbonization efforts. Thus, Vistra requests that ISO-NE consider making such lower emitting resources eligible to be awarded clean energy certificates. ISO-NE could develop a gradation approach, such that lower emitting resources can be awarded partial clean energy certificates to appropriately account for their measurable contribution to decarbonization.
3. **Impacts of Negative Pricing**. Resources awarded clean energy certificates under FCEM could be incented to offer energy at negative prices, depending on the FCEM clearing price. ISO-NE should evaluate the expected prevalence of negative pricing over time, and consider whether FCEM credits will need to be increased over time to account for reduction in energy revenues resulting from increased negative prices.
4. **ELCC**. The proposed FCEM design does not assume ISO-NE's anticipated future reliance on ELCC for calculating each resource's contribution to achieving resource adequacy. Vistra believes that these modeling efforts should assume that the region will move to an ELCC approach and model these different designs relying on that approach. This is critical to ensure that the models accurately account for the capacity contributions for resources, and determine the costs and benefits of such designs for consumers.

While these comments focus on the FCEM design, Vistra believes these comments apply equally to ICCM, and thus requests that ISO-NE consider these comments as it develops its modeling approach for ICCM as well.

Please let me know if you have additional questions.

Regards,

Andy Weinstein

April 10, 2021

From: Reliable Energy Analytics LLC (REA)
To: ISO New England Market Development

Reliable electricity is the life blood that nourishes our economy, sustains our standard of living and helps humanity achieve health and happiness. Electrification is the only viable solution to reduce Greenhouse gases (GHG) from all sectors of the economy, including transportation, heating, manufacturing and construction. Ensuring the reliable flow of electricity is an uncontestable requirement, that cannot be compromised by poor market designs, as was experienced in Texas, February 2021 that resulted in $9,000/MWh energy prices and California during the August 2020 heat wave, as indicated by this statement in the final root cause analysis report issued by CAISO, et al: "*The Final Analysis confirms there was no single root cause of the August outages, but rather, finds that the* ***three major causal factors contributing to the outages were related to extreme weather conditions, resource adequacy and planning processes, and <u>market practices</u>.***" [1]

REA proposes the following "litmus test" for each Pathway option under consideration within ISO-NE's study plans, and additional objectives to consider for all "Pathways to the Future Grid" that are under consideration by NEPOOL, Potential Future Market Framework Options (A, B, C):

1. Does the market design prioritize and achieve the acquisition of capacity resources and essential grid services needed for reliability, balancing, and "energy adequacy"? The following findings by Dr. Frank Felder in his report to NEPOOL on 1/6/2021 [2] provide some useful insights, in this regard.
    a. *[2] "The reliability criteria and metrics should be specified in order to establish the balancing services needed to plan and reliably operate the bulk power system given increasing penetration of VRERs, perhaps as part of the NEPOOL's ongoing Future Grid Reliability Study effort"*
    b. *[2] "Pathways may not procure sufficient amounts and types of balancing resources that the region needs to operate the grid reliably or if they do, it is not clear that they do so in the most cost-effective manner."*
    c. *[2] <u>"If a pathway avoids or minimizes the double capacity payment issue, that does not, however, mean that the pathway necessarily efficiently procures and/or retains the necessary balancing resources that are needed for reliability."</u>*
    d. *[2] "Finally, neither the FCEM nor the ICCM explicitly address the balancing resource issue."*
    e. *[2] "Net carbon pricing does not explicitly address the balancing resource issue. "*
2. REA proposes the following objective guidelines for all "Pathways to the Future Grid" market designs, that may be considered by ISO New England and/or NEPOOL:
    a. Achieve State Energy Goals as a top priority, that properly charges the beneficiaries of each State, without burdening other States' consumers with the costs of another States' program
    b. Engage State regulators, local utilities and other stakeholders in the pursuit of a market solution for energy adequacy that requires the approval of State representatives, NEPOOL and parties responsible for grid reliability in the final design
    c. Be flexible enough to integrate new technologies to generate electricity and manage grid operations

d. Be market based so that each resource is properly valued for the benefits/services it provides to grid operations, consumers, the environment and society at large
e. Efficiently secures future capacity grid services using a just-in-time approach that eliminates the excessive over-buying of capacity that occurs today by ISO's while supporting new, long term capacity construction projects
f. Incentivizes investment in the most beneficial and cost-effective technologies used to generate electricity and manage grid operations reliably (including DR) that achieves Societal and Environmental goals determined by each individual State, such as clean air and water, while ensuring grid reliability and resilience
g. Provide a vibrant. 24x7, marketplace for Green Energy Buyers, including States and local utilities, to secure PPA's and Investors to trade, which supports the acquisition of Capacity, Energy and REC's.
h. Ensure the acquisition of sufficient grid services capacity needed to ensure a reliable electrical system for all, at a just and reasonable cost to consumers that provides adequate revenues to resource owners that commit to provide their valuable services, when called upon by the ISO
i. Shift from purchasing "plain old capacity" to acquiring "essential grid services" from DER, to support FERC Order 2222, and traditional generators, as determined by ISO New England based on reliability requirements
j. The market solution for resource adequacy and power system operational needs must coexist in a symbiotic relationship to produce an optimal outcome for a reliable electric grid, in harmony with State goals and objectives, at a just and reasonable cost and avoid the market design flaws that plagued California during the 2020 heat wave and Texas in the February 2021 extreme weather conditions that led to $9,000/MWh electricity prices.

[1] http://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf
[2] https://nepool.com/wp-content/uploads/2021/01/NPC_20210107_Felder_Report_on_Pathways_rev1.pdf

Thanks,

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