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Request for Proposals

for

Energy Generation

and

Transmission Projects

Issued by the
Maine Public Utilities Commission

35-A M.R.S. § 3210-I

December 19, 2025

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1. OBJECTIVE AND OVERVIEW OF PROCESS

1.1 Objective

In accordance with 35-A M.R.S. § 3210-I (the Statute), the Maine Public Utilities Commission (the Commission) issues this Request for Proposals (RFP) to promote the development of energy resources in Northern Maine and the delivery of power from those resources to the system and market operated and administered by ISO New England (ISO-NE). In accordance with that objective, the Commission is seeking viable and cost-effective proposals for the development and construction of energy generation projects in Northern Maine and a transmission line or lines to connect such generation projects with the ISO-NE system. The transmission line will interconnect with the ISO-NE system at the northern terminus of the facilities constructed as a result of ISO-NE's Longer-Term Transmission Planning (LTTP) Solicitation, described below. In evaluating proposals, the Commission will give preference to projects that provide the lowest delivered cost of contract products and exhibit an ability to harmonize the generation and transmission components.

1.2 Overview of Process

The Commission seeks bids for the sale of energy and renewable energy credits[1] (RECs), preferably submitted as a joint proposal that pair and synchronize the development of one or more generation facilities in Northern Maine (the Generation Component) with a transmission line or lines necessary to connect at least **1,200 MW** of resources to ISO-NE (the Transmission Component). Together these components are referred to herein as the "Project." Awards will result in **two contract types**:

Generation: One or more 20-year term **Power Purchase Agreements** (PPAs). PPA payments will be **contingent on deliverability** (i.e., payments will be made only for delivered energy).

Transmission: A **Voluntary Agreement (VA)** between the appropriate agencies in the Coordinating States[2] and transmission developers which will provide cost recovery through a cost-based **formula rate** approved by the Federal Energy Regulatory Commission (FERC) under **Section 205 of the Federal Power Act (FPA)**. The VA will include cost allocation, cost recovery, cost containment (e.g., ROE adjustments for cost overruns and other relevant provisions). A **Section 205 filing** seeking FERC approval to effectuate the VA Term Sheet is required **promptly after selection**.

The developers proposing the individual components of each Project are strongly encouraged to submit **one joint proposal,** which must include agreed-upon terms of

[1] For purposes of this RFP, the term "renewable energy credit" has the same meaning as "renewable energy certificate."

[2] The term "coordinating states" is defined in the Order issuing this RFP.

a Coordination Agreement, as described below, specifying how they will coordinate the development and construction of each component and allocate and manage the associated risks of development, construction, and operation among themselves. The Commission will, however, consider **standalone proposals** for each component, which must include a draft term sheet of a Coordination Agreement containing terms the bidder would agree to if paired with another standalone proposal for the complementary component.

The procurement is structured so both the Transmission and Generation Components of the selected Project can submit interconnection requests in the **ISO-NE Cluster Request Window anticipated for October–November 2026 (the "2026 Cluster Window")**. If either component is unable to enter the 2026 Cluster Window, *both* Components must delay and enter a subsequent cluster study together.

The expectation that the Transmission and Generation Components enter the 2026 Cluster Window is contingent on at least two ISO-NE processes:

1) **ISO-NE LTTP Solicitation.** ISO-NE issued the LTTP RFP March 31, 2025 to select a Longer-Term Transmission Upgrade (LTTU) to address limitations on transfers of energy from northern New England to southern New England and the development of new infrastructure to support the integration of at least 1,200 MW of onshore wind.[3] On November 14, 2025, ISO-NE released a summary of the six proposals it had received, all of which proposed to develop a new substation near Pittsfield, Maine, that would allow for the interconnection of transmission delivering energy from Northern Maine.[4] This procurement is contingent on the selection of an LTTU for inclusion in the Regional System Plan Project List.

2) **Third Maine Resource Integration Study (MRIS).** Following the LTTP selection, ISO-NE will incorporate the selected LTTU into the transmission planning base case for the Third MRIS and identify the remaining facilities needed to interconnect approximately 1,200 MW from Northern Maine as a **Cluster Enabling Transmission Upgrade (CETU)**. The Transmission Component selected in this RFP must be submitted as an Internal **Elective Transmission Upgrade (ETU),** identical to and ultimately taking the place of that CETU. The Transmission Component will be selected by the Commission prior to the release of the Third MRIS. The Transmission Component selected in this RFP must subsequently be updated as needed to conform to the final

[3] See https://www.iso-ne.com/system-planning/transmission-planning/longer-term-transmission-studies.

[4] See https://www.iso-ne.com/static-assets/documents/100030/2025_lttp_rfp_proposal_summaries_rev1_clean.pdf

Third MRIS. The final Third MRIS is anticipated to be released prior to the close of the Cluster Request Window in Fall 2026.[5]

1.3 Coordination with Other New England States

The Commission is coordinating with other New England states in the evaluation of proposals and consideration of a joint selection in which all or some other combination of the Coordinating States would participate. Appendices O and P contain the additional evaluation requirements and parameters of the potential involvement by Connecticut, Massachusetts, Rhode Island, and Vermont, respectively.

1.3.1 RFP Issuance and Proposal Submission

The Commission will share bids submitted in response to this RFP with Massachusetts, Rhode Island, and Vermont. Bidders need not submit additional bids to those states. To be considered by Connecticut, bidders must submit an **identical** bid to Connecticut in accordance with their Zero Carbon Request For Proposals.[6] Proposals will be reviewed for joint selection by the applicable entity(ies) in the Coordinating States in accordance with their respective state authorities and the requirements.

Developers must offer the same bid with identical commercial terms and prices in order to be considered by any coordinating state or entity.

1.3.2 Evaluation and Selection

Commission Staff, ensuring the protection of confidential information, will share proposals with Coordinating States and other Maine agencies. Each coordinating state will evaluate proposals in accordance with their relevant state authorities and requirements.[7] Commission Staff will coordinate with other participating states and entities, as applicable, to select project(s) to recommend to the Commission. The Commission will then consider this recommendation and make a final selection in a public deliberative session. The overall delivered cost of contract products, including transmission costs, will be a primary factor in the evaluation of bids,

[5] See August 11, 2025 Memo on the Third MRIS from ISO-NE, available here: https://www.iso-ne.com/static-assets/documents/100026/2025_08_11_third_maine_resource_integration_study_memo_update.pdf

[6] At the time of issuing this RFP, Connecticut has not yet issued this RFP. Once issued, a notice will be filed on this docket. A draft of the RFP is available here: https://www.dpuc.state.ct.us/DEEPEnergy.nsf/c6c6d525f7cdd1168525797d0047c5bf/fa112c7347b2722485258d61006fe2b1?OpenDocument.

[7] The specific evaluation requirements for each of the potential coordinating states are set forth in Appendices O and P.

including a determination of the amount of generation procured by the Commission and other Coordinating States.

1.4 Timeline

The Commission anticipates the following timeline for key events relating to this procurement and other dependent regional processes. Other Coordinating States may have different procedural steps that will also be built into this timeline.

Event	Expected date
RFP issued	December 19, 2025
Intent to Bid Form due for Standalone Transmission Proposals/Standalone Generation Non-Disclosure Agreement	January 23, 2026
Final Date for Submitting Questions	February 13, 2026
Proposals due	February 27, 2026
Commission review and negotiation	Begins February 27, 2026, ongoing
Signed Term Sheet for Coordination Agreements for Joint Proposals due	April 1, 2026
Commission decision and award	No later than May 2026
Finalize Key Contract Terms	No later than July 2026
Finalize and Execute Coordination Agreement(s)	No later than July 10, 2026
Transmission developer files FERC §205 petition	No later than July 2026
ISO-NE LTTP selection recommendation	By Sep 30, 2026
ISO-NE final Third MRIS released	Prior to close of Cluster Request Window (November 2026)
ISO-NE Cluster Request Window opens	October 2026
ISO-NE Cluster Request Window closes	November 2026

1.4.1 Regulatory Approvals and Post-Selection Steps

After selection, the **transmission developer** will be required to:

1) Promptly initiate the process for seeking FERC approval of the terms and conditions in an agreed upon term sheet attached to a State VA by filing a Section 205 proceeding seeking approval of the term sheet in accordance with the FPA;

2) Update the Project's design to ensure consistency with the LTTU and the final Third MRIS; and

3) Seek a certificate of public convenience and necessity (CPCN) from the Commission pursuant to 35-A M.R.S. 3132.

After selection, the **generation developer(s)** will engage in PPA negotiations with the applicable entity(ies) for each of the Coordinating States. In addition to following each state's review and approval process, the generation developer(s) will be expected to negotiate PPAs with each coordinating state or relevant entity. In addition to the requirements set forth in this RFP, bidders that wish to be considered by all Coordinating States and entities should comply with the requirements set forth in Appendices O and P.

1.5 RFP Documents and Information; Contact Persons

Additional information about this RFP, including a copy of the Act, and required forms and instructions for submitting bids, are available on the RFP's website: Request for Proposals for Renewable Energy Generation and Transmission Projects Pursuant to the Northern Maine Renewable Energy Development Program

All changes, updates and supplements to the RFP and related materials will be posted to the RFP Website. Bidders are responsible for obtaining these updates and additions.

Bidders may submit questions or request additional information by email to NorthernME.RFP.PUC@maine.gov on or before February 13, 2026, which will be shared with any coordinating state or entity covered by the Protective Order issued in this docket. Commission Staff will maintain a publicly accessible question and answer log.

2. QUALIFYING PROJECTS

This section describes the eligibility criteria for proposals submitted in response to this RFP.

2.1 Joint and Standalone Proposals Permitted

The Commission strongly prefers **joint proposals** that combine a Transmission Component with a Generation Component. The Generation Component may be a combination of multiple generation facilities. Each joint bid must be governed by a **Coordination Agreement**[8] between the generation and transmission developers that delineates, among other things, each Component's roles and responsibilities, construction / interface risk management, interconnection and operational coordination (including outage / curtailment management[9]), information-sharing, dispute resolution, and a shared milestone schedule.

Standalone proposals for each component will be accepted and reviewed. Standalone proposals must include a draft term sheet of a Coordination Agreement that the bidder would be willing to enter into if the Commission pairs it with a complementary component. If standalone projects receive an award, their award will be contingent on being able to finalize the Coordination Agreement with the complementary component no later than July 10, 2026.

Developers participating in a joint bid are permitted, but not required, to also submit a standalone bid for their component.

Generators intending to submit a standalone bid must submit a Nondisclosure Agreement as described below in Section 2.1.1.

2.1.1 Standalone Transmission Developers Must Complete and File an Intent to Bid Form

To enable generation developers to submit a standalone bid, any developer that intends to submit a standalone transmission bid must submit a confidential **Intent to Bid Standalone Transmission Form** (available, with instructions, at Appendix

[8] A term sheet of the Coordination Agreement is permissible for purposes of submitting proposals, and the Coordination Agreement must be finalized by July 10, 2026.

[9] In accordance with Schedule 25 of the ISO-NE Open Access Transmission Tariff, there are no physical transmission rights for Internal ETUs. An Internal ETU selected through this RFP would be operated the same as a Pool Transmission Facility (PTF), and generation units interconnecting to the facility would be subject to ISO-NE least-cost security-constrained economic dispatch operated and scheduled by the System Operator without recognition of physical transmission rights. Generation developers are encouraged to seek to minimize curtailment by assembling a Generation Component combining Generation Facilities with complementary production profiles or by using energy storage.

H), which will include, among other things, the location of the northern terminus of the Transmission Component and the capacity of the Transmission Component.

All Intent to Bid forms must be submitted to the Commission, by filing in Docket No. 2025-00361, no later than 5:00 p.m. January 23, 2026. Any failure to timely provide the **Intent to Bid Standalone Transmission Form** may, in the Commission's discretion, render the standalone transmission bid ineligible for consideration.

If any Intent to Bid forms for transmission are submitted to the Commission, developers intending to submit a standalone bid for generation must sign a Nondisclosure Agreement (available with instructions **Appendix I**), before being granted access to redacted versions of the Intent to Bid forms. Non-Disclosure Agreements must be filed in Commission Docket No. 2025-00361 on or before January 23, 2026, after which Commission Staff will contact the submitting developers to facilitate access to redacted Intent to Bid forms.

2.1.2 Discouragement of Exclusivity Agreements

To encourage competition, the Commission discourages, but does not prohibit, **exclusivity agreements** between developers of the Generation and Transmission Components. Developers are strongly encouraged to submit multiple bids with different developer pairings.

2.2 Generation Eligibility

A Generation Component must meet statutory eligibility criteria as well as additional eligibility criteria described in this section.

2.2.1 Statutory Criteria

A Generation Component must be physically located in Northern Maine,[10] have commenced construction after July 31, 2024[11] and must meet the requirements for a Class I or Class IA resource, as defined in Maine Statute, 35-A M.R.S. § 3210 (except that the following are not qualified generation projects: (i) biomass generators fueled by landfill gas or by anaerobic digestion of agricultural products; and (ii) waste-to-energy generators fueled by municipal solid waste).

[10] "Northern Maine" means Aroostook County and any other area of the state in which the retail market is administered by the Northern Maine Independent System Administrator (NMISA). 35-A M.R.S. § 3210-I(1). **The Transmission Component selected in the procurement will not interconnect with the NMISA system.**

[11] The Commission may, in its discretion, consider awarding contracts to one or more generation facilities on which construction commenced prior to July 31, 2024 if the Commission finds that it meets the criteria in 35-A M.R.S. § 3210 (3)(B)(2).

2.2.1.1 Option to Include Storage

A proposal may also include an energy storage system, which, for the purpose of this RFP, means a commercially available technology that uses mechanical, chemical, or thermal processes for absorbing energy for use at later time.

Proposals to include an energy storage system must demonstrate how the storage system will be designed and utilized to maximize use of the transmission line and reduce costs for ratepayers. Incentive structures may be proposed and must explicitly demonstrate that any storage proposals that include such incentives produce a net benefit to ratepayers relative to a no-storage counterfactual.

The counterparties that enter into PPAs for generation (including electric utilities) will not be expected to dispatch or otherwise manage an energy storage system.

2.2.1.2 Additional Criteria

A Generation Component must meet the following additional eligibility criteria:

1) Commit to seeking interconnection at the Capacity Capability Interconnection Standard (CCIS) and describe how obtaining a Capacity Supply Obligation (CSO) will benefit buyers.

2) Provide milestones consistent with the RFP schedule (e.g., selection of an LTTU in the LTTP solicitation by Sept. 30, 2026; MRIS in Oct. 2026; Cluster Request Window Oct–Nov 2026) and aligned to begin commercial operations on approximately the same schedule as the Transmission Component.

3) Demonstrate the Project has, or will have, the prerequisites to submit an interconnection request in the Fall 2026 ISO-NE Cluster Request Window. (Anticipated Oct–Nov 2026).[12]

4) Commit to utilizing the New England Power Pool Generation Information System (NEPOOL GIS) to enable Coordinating States to account for delivery of clean energy toward statutory goals.

[12] Reference Section 3.4.2 of the ISO-NE Large Generator Interconnection Procedures: https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_2/sch22/sch_22_lgip.pdf

2.3 Transmission Eligibility

A Transmission Component must meet statutory eligibility criteria as well as additional eligibility criteria described in this section.

2.3.1 Statutory Criteria

A Transmission Component must be capable of delivering at least 1,200 MW of energy to the ISO-NE system from the Generation Component to the LTTU Northern Terminus in the Pittsfield, ME, area. The transmission developer must, in the Commission's determination, demonstrate technical and financial capacity to successfully construct, develop, and operate the Transmission Component and to complete the ISO-NE Interconnection Process.

2.3.2 Additional Criteria

A Transmission Component must meet the following additional eligibility criteria:

1) Commit to promptly submit the FPA Section 205 filing effectuating the VA term sheet for FERC approval following selection, consistent with the RFP timeline.

2) Commit to update the Transmission Component to conform to the CETU identified in the final Third MRIS.

3) Demonstrate the Transmission Component has, or will have, the prerequisites to submit an interconnection request for an Internal ETU in the Fall 2026 ISO-NE Cluster Request Window (Anticipated Oct–Nov 2026) and that the interconnection request will meet the requirements to take the place of the CETU identified in the Third MRIS.[13]

4) Commit to obtaining a certificate of public convenience and necessity (CPCN) from the Maine Commission.

[13] *See* Section 3.3 of the ISO-NE ETU Interconnection Procedures, available at https://www.iso-ne.com/static-assets/documents/2015/02/sch_25.pdf.

3. PROPOSAL TERMS AND CONDITIONS

3.1 Coordination Agreement

Proposals must demonstrate the ability and willingness for the developers of the Transmission Component and Generation Component to coordinate. Accordingly, all proposals must include a term sheet for a Coordination Agreement between the transmission and generation developers. In addition to the required information described in Section 5.2 below, the Coordination Agreement must, at a minimum, describe how the developers of each component will:

a) mandate information sharing on key topics like site control and project development milestones;

b) manage and allocate risk between the developers;

c) coordinate development to ensure that the transmission and generation components are placed in service at or as near the same time as possible;

d) set forth an efficient dispute resolution plan; and

e) include any other terms that may serve to minimize project-on-project risk.

3.1.1 Standalone Bids

All standalone bids must submit a draft term sheet of a Coordination Agreement that it would enter into if paired by the Commission with a complementary component.

For standalone bids, the draft term sheet should be submitted at the same time as the proposal**.**

3.1.2 Joint Bids

To provide additional time to negotiate a Coordination Agreement, proponents of joint bids may submit the term sheet for their Coordination Agreement on or before April 1, 2026.

Even though proponents of joint bids will have extra time to memorialize their Coordination Agreement, joint bids should still be submitted with a predetermined understanding of the allocation of risk between the developers.

3.2 Requirements for Generation Component

Proposals should provide for the development, construction, and operation of qualified generation facilities located in Northern Maine that will be connected to and capable of delivering energy to the ISO-NE system using the Transmission Component selected in this RFP process. Bidders may submit Proposals that include multiple generation facilities as part of the Generation Component of the Bid.

Proposals for the Generation Component must adhere to the following terms and conditions. The Coordinating States may have additional terms and conditions for contracting generation, which will be set forth in each State's model PPA.

3.2.1 Term Duration

The preferred term of a PPA is 20 years with the 20-year period commencing at the time the Generation Facility begins delivering energy to the ISO-NE system over the Transmission Component.

3.2.2 Expected Commercial Operation Date (COD)

The Generation Facility(ies)) is / are expected to reach commercial operations on or about the time as the Transmission Component reaches commercial operation as set forth in the Coordination Agreement, which should also coincide with the COD for the LTTU.

3.2.3 Delivery Point

Contract products will be delivered to the ISO-NE market where the project interconnects to the Transmission Component. For the avoidance of doubt, delivery will not be accepted prior to the in-service date of the Transmission Component.

3.2.4 Contract Products

Contract products are energy and renewable energy credits.

3.2.4.1 Capacity Value

"Capacity Value" includes any net value deriving from capacity-related products, including but not limited to ISO-NE Forward Capacity Market ("FCM") payments (or any successor market), and including but not limited to payments or charges resulting from any Forward Capacity Auction, reconfiguration auction, bilateral agreement or transfer for capacity, performance payments, and any associated penalties or charges (or the equivalent).

Some or all of the procuring entities may be interested in capturing Capacity Value in their respective PPA price.

Any Bidder intending to pursue ISO-NE Capacity Market participation for the Resource during the term of the PPA, including seeking a Capacity Supply Obligation, must clearly state this intent in the Proposal (the Capacity Market Election)[14] and will be held to this during contracting. All Proposals, regardless of Capacity Market Election, must provide an additional, alternative "Capacity Value Price" that should be a $/MWh Energy PPA price under which Capacity Value (if any) received by Bidder would serve as a reduction of payment under the PPA.

3.2.5 Product Pricing

Generators will be paid based on the quantity of energy (MWh) delivered to the Delivery Point.[15] Proposals may be structured as physical or financial transactions. Separate prices must be proposed for each product offered.

Proposals for each Generation Facility should, at minimum, include the following pricing proposals: (1) a proposal for a fixed price[16] contract; and (2) an indexed price consistent with the indexed pricing mechanism set forth in Appendix B without any proposed escalators. Optionally, proposals may also contain an indexed price consistent with the indexing mechanism set forth in Appendix B with any proposed escalators.[17] The Commission may select any of these options.[18] Pricing offers submitted in response to this RFP shall be firm and final bids binding on the bidder. However, the Commission may, in its discretion, request amendments to price or waive this requirement, as appropriate. In the event the Commission requests bid modifications, the Developer will have the option, but is not required, to amend or refresh its bid price.

As to Capacity Value (*see* Section 3.2.4.1, *supra*), any proposal making the Capacity Market Election must also provide an additional "Capacity Value Price"

[14] An affirmative Capacity Market Election is indicated by checking the relevant box in Appendix L, Tab B.

[15] To ensure that the ratepayers who will ultimately support these projects do not pay for energy that cannot be utilized, generators will not be paid for energy delivered when the transmission component is out of service. Generators should address this risk in their Coordination Agreements with transmission developers.

[16] All fixed price proposals should be a flat, non-escalated price.

[17] The indexed pricing mechanism in Appendix B (also attached to the MPUC Model PPA) provides for (1) a bidder selected price and price cap and (2) various generation specific inflation indexation formulas. The earlier of the generation developer's Financial Investment Decision or twenty-four months from issuance of a CPCN for the Transmission Component, the initial price may be adjusted based on the lesser of the price cap and the indexed price at the time of the adjustment.

[18] Each of the Coordinating States should receive identical pricing proposals, and bidders should be prepared for the Coordinating States to select different pricing options.

that should be a $/MWh Energy PPA price under which Capacity Value (if any) received by Bidder would serve as a reduction of payment under the PPA.

Any bid that includes an energy storage system must include (1) a pricing proposal with the storage system and (2) a pricing proposal without the storage system.

Pricing for Environmental Attributes should not exceed governing Alternative Compliance Payments for any coordinating state.

Any contingencies associated with a proposal must be clearly described and supported in the proposal. To the extent any contingency identified by a bidder would affect the proposed pricing, the contingency must be resolved prior to any award by the Commission.

3.2.5.1 No Payment During Negative Price Intervals

Generators will only be paid for delivered energy when the Locational Marginal Price is greater than or equal to $0.00 per MWh at the Delivery Point. During times of negative pricing, generators may elect to operate during negative pricing, which will result in a reduction of payment under the PPA, or suspend service.

In accordance with 35-A M.R.S. § 3149, the PPA will include a provision that requires the reduction of payments to the bidder by the stranded costs arising from energy produced during negative price intervals, including those paid by the T&D and / or purchasing entity (Purchasing Entity).

”Stranded costs” are the above market costs incurred by the Purchasing Entity and may arise from either (a) the energy price paid by the Purchasing Entity to the project or (b) the negative locational marginal price (LMP) paid by the Purchasing Entity to ISO-NE for each MW produced by the project during a negative hour. The standard form contract contemplates: (i) a $0/MWh contract price paid to the project when the LMP in any hour is negative; in addition to (ii) a reduction of the monthly payment to the project in an amount equal to the Purchasing Entity’s negative LMP payment to ISO-NE, which could result in the seller being invoiced by the Purchasing Entity in months when there is not enough positive value from energy produced to fully offset any negative value. This issue is addressed in the Maine model PPA.

As set forth in 35-A M.R.S. § 3149, bidders may request an exception from this requirement. Any request for exception must be included with and fully explained and substantiated in the proposal and will be considered during the evaluation process.

3.2.6 Security

Performance Security is required for the selected Project and may vary by state.

Acceptable forms of Project and Performance Security are: (1) cash (U.S. currency) or (2) an irrevocable, transferable and unconditional standby letter of credit issued by a U.S. commercial bank or a foreign bank with a U.S. branch with such bank having a minimum credit rating of A- from S&P or A3 from Moody's.

The utility counterparties are not required to post security.

3.2.7 Federal Tax Credits and Unanticipated Revenue

No generation proposal should assume receiving the federal Investment Tax Credit (ITC).The Maine Model PPA contains a mechanism for sharing (90/10) any revenue or award received by the project as a result of changes to federal or state policy that were not contemplated at the time of bid submission, including but not limited to, a return of federal tax credits or other grants or programs by the federal or state governments. *See* the Maine Model PPA in Appendix G; *see also* Appendix P (Coordinating States sample PPAs). This provision includes an accounting method and mechanism for reducing payments made under the PPA in the event the developer receives or is eligible for additional revenue not contemplated under the current bid.

3.2.8 Standard Form Contracts

Products will be contracted via a PPA between the generator(s) and the relevant counterparties / buyers. Developers of the Generation Component are expected to adopt the standard form contracts presented in Appendix P or posted in Commission Docket No. 2025-00361 for each of the Coordinating States. Any proposed material changes to the contracts are discouraged and any such changes will be weighed accordingly during evaluation of the proposal. **Any such change must be identified by a redline to the standard form contract and submitted with the proposal and explained in comments within that redline copy**.

3.3 Requirements for Transmission Component

Proposals should provide for the development, construction, and operation of a transmission line or lines and associated infrastructure necessary to deliver energy produced by the Generation Component to the ISO-NE system. The Transmission Component proposal must include all transmission facilities identified in Scenario 2 of the draft Third MRIS results (or must be electrically equivalent), including transmission line, reactive device, and substation facilities.[19] Any deviations from the Scenario 2 facilities must be explained in detail.

[19] *See* Draft Third MRIS Results at Slide 14: https://www.iso-ne.com/static-assets/documents/100012/a02_third_maine_resource_integration_study_june2024_non_ceii.pdf

The Transmission Component will be developed via a Voluntary Agreement (VA) between the developer and the Commission or the appropriate state agencies representing one or more of the Coordinating States.[20]

Proposals for the Transmission Component must adhere to the following terms and conditions.

3.3.1 Voluntary Agreement

The Transmission Component will be procured via a VA between the Transmission Developer and the appropriate agency or organization representing each or of all of the Coordinating States.[21] Accordingly, the transmission developer will recover its costs through a FERC-approved transmission rate. The VA will document the cost allocation, cost recovery, cost containment, and other relevant provisions associated with the Transmission Component.

Upon receiving an award, the selected transmission developer must promptly initiate a Section 205 proceeding at FERC to effectuate the VA term sheet, with the support of the Coordinating States.[22] Transmission rates will be set forth in a new attachment to the ISO-NE OATT.

3.3.1.1 Model VA Term Sheet

A model term sheet for the Voluntary Agreement (Model VA Term Sheet) is attached as Appendix F.

With the exception of certain provisions with clear instructions regarding permissible modifications, transmission developers are expected to adopt the model term sheet. Redlines to the term sheet will not be accepted absent extraordinary circumstances,[23] and any proposed modification will be weighed accordingly during evaluation.

For the provisions in the Model VA Term Sheet relating to ROE and cost management, transmission developers should treat the model provisions as a

[20] 175 FERC ¶ 61,225, Docket No. PL21-2-000 (June 17, 2021).

[21] *See* 2021 Policy Statement: https://www.ferc.gov/media/e-2-061721.

[22] ***Bidders should not, however, submit a preemptive filing with FERC prior to receiving an award, as that may be counterproductive and slow the process.***

[23] The Commission underscores that, due to the compressed timeframe of this procurement, it will not entertain protracted negotiations on the model term sheet. Extended negotiations may render the Project unable to obtain the requisite government approvals to submit their project within the 2026 Cluster Window. Accordingly, red lines to provisions other than the provisions specifically identified in the Model VA are strongly disfavored and, absent extraordinary circumstances, are unlikely to be accepted. Bidders should instead be prepared to comply with the terms of the model term sheet.

baseline from which bidders may offer a lower ROE or stronger cost containment mechanism to enhance the competitiveness of their bid. As set forth in Appendix D (Transmission Proposal Instructions), any proposal that includes redlines to the term sheet must explain, in detail, why the modifications to these provisions create stronger cost management incentives for the transmission developer. The Commission will not consider any redlines that it determines, in its discretion, propose a cost containment measure that provides less protection for ratepayers from cost overruns than the model term sheet.

3.3.1.2 Cost Estimate

The Model VA Term Sheet contemplates a formula rate driven by the cost of the Transmission Component.

Cost estimates should be provided in the proposal and will be reviewed for reasonableness during bid evaluation.

3.3.1.3 Cost Management and Containment

The model cost management measure in the Model VA Term Sheet includes a reduced Return on Equity (ROE) for cost overruns, delayed project completion, and transmission outages exceeding prescribed thresholds.

This model provision should be a floor, or baseline, from which bidders can offer stronger cost containment mechanisms to make their bid more competitive. Additional measures that the Coordinating States may consider include, but are not limited to, long-term caps on the revenue requirement and stronger reductions in ROE for cost overruns.

Any proposal that differs from the model provision must be accompanied by a clear explanation for why this measure is more beneficial to ratepayers by providing stronger incentive to contain costs. To the extent the Coordinating States determine that the modified provision does not satisfy this standard, the proposed modification will be set aside and the model provision will control.[24]

3.3.1.4 Post-Final Third MRIS Adjustment

Because bids in this procurement are due prior to ISO-NE's selection of an LTTP proposal and prior to the release of the Final Third MRIS, there may be a cost adjustment based on results of the Final Third MRIS. The Final Third MRIS is anticipated to be published prior to the close of the Cluster Request Window in 2026 and will specify the infrastructure, including transmission line, reactive device, and substation facilities needed to interconnect 1,200 MW of generation from Northern Maine. After bid selection and award, the cost

[24] Bidders will be notified of any such determination during the selection process and have the opportunity to accept the model provision or withdraw their bid.

estimates for the Transmission Component will be adjusted in accordance with the process set forth in Appendix C.

3.3.1.5 Right to Terminate and Abandoned Plant Incentive

In exchange for their right to terminate at certain milestones, the Coordinating States will support the Transmission Component developer's pursuit of FERC approval of an abandoned plant incentive.

3.3.1.6 Performance Incentives

Bidders may add a provision(s) in the Model VA Term Sheet regarding any intent to seek approval of certain performance incentives, such as the Construction Work In Progress incentive, that would be useful in making their bid more competitive. However, any proposal for a performance incentive must be accompanied by an explanation for why such incentive will benefit ratepayers and enhance viability of the project.

However, bidders should not propose inclusion of the RTO Adder here or elsewhere in the Model Term Sheet, as it will not be approved by the Coordinating States.

3.3.1.7 Transmission Outages

The Model VA Term Sheet provides an example of a provision that bidders may include in their proposal regarding transmission outages that would, if proposed, make their bid more competitive.

3.3.1.8 Expected COD

Proposals should set forth the expected COD. In accordance with the proposed Coordination Agreement, the Transmission Component should reach commercial operation on or about the time when the Generation Component reaches commercial operation. These dates should also be aimed to align with, but should not be before, the LTTU's in-service date.

As set forth in the Model VA Term Sheet, bidders should propose a disincentive for exceeding the projected COD, which should also be reflected in the Coordination Agreement.

3.3.2 Route and Site Control

As set forth in 35-A M.R.S. § 3210-I, proposals should use, to the extent practicable, existing utility and other rights-of-way and existing transmission corridors. The Southern Terminus of the Transmission Component is expected to be at or near Pittsfield, Maine, and the specific location will be determined by the conclusion of the ISO-NE LTTP solicitation process and ISO-NE's issuance of the Third MRIS. For the purposes of developing a proposal and developing the

Proposal Cost Estimate, assume a Southern Terminus at location (44.79515 N - 69.36574 W).

Proposals should include details regarding the bidder's plan for achieving site control and specify the expected timeline for doing so. To the extent that proposals rely on eminent domain or joint use of existing rights-of-way (*see, e.g.,* 35-A M.R.S. § 3136 and 35-A M.R.S. § 711 (1)), the Proposal should include a detailed description of its proposed process and timeline for achieving site control through reliance on eminent domain and / or joint use of existing rights-of-way and alternatives.

4. EVALUATION CRITERIA

The Commission will evaluate eligible proposals based on the objectives and criteria set forth in the Statute and this RFP in order to facilitate the efficient and cost-effective development of energy resources and transmission in Northern Maine.

The Commission will evaluate the projects in three stages: (1) an initial screen for eligibility and viability; (2) a quantitative and qualitative analysis of the benefits of the proposal; and (3) a final ranking based on cost / price. In the first stage, projects will be screened to ensure they can satisfy the requirements and purpose of this procurement. In the second and third stage of evaluation, the Commission will consider the results of both the quantitative and qualitative factors and rankings to determine projects for selection.

In the first stage, the Commission will screen projects for eligibility, as set forth in Section 4.1, and for viability. In addition to eligibility requirements, Projects and Proposals must satisfy each of the following factors to move on to Stage Two of the evaluation:

a) Ability to complete the ISO-NE interconnection process;

b) For transmission developers, a demonstrated ability to manage FERC processes;

c) Demonstrated site control or a viable path to site control;

d) Technical and financial capacity to successfully construct, develop, and operate the project; and

e) Overall viability of the Project or Proposal, including but not limited to feasibility and design of and commitment, willingness, or ability to coordinate with or among complementary component(s).

If the Commission, in its discretion, determines that any Project or Proposal is unable to satisfy any factor in Stage One, the bidder will receive notice of that shortcoming and be

given an opportunity to cure the deficiency within ten (10) business days.[25] If the bidder is unable to modify or clarify its bid to the Commission's satisfaction, the bid will be set aside and not considered in the subsequent evaluation stages.

In the second stage, the Commission will assign proposals a score based on multiple non-price criteria. Consistent with 35-A M.R.S. § 3210-I(2)(B) and (3)C), the Commission will consider the following qualitative and quantitative criteria:

a) Strength of economic benefits, as defined below;

b) Strength of bidder qualifications;

c) The anticipated contribution of each proposal toward Maine's achievement of its renewable energy goals under 35-A M.R.S § 3210;

d) Strength of Coordination Agreement / ability to coordinate among components[26];

e) Strength of the feasibility of the Project, including but not limited to community engagement and support, plausible path to financing, and expectations regarding site control;

f) Any redlines to the model VA term sheet or PPA[27];

g) Maximizing use of the transmission line;

h) Expected Commercial Operation Date;

i) Future expandability of the Project or Proposal;

j) Ability to advance regional coordination efforts among the Coordinating States and entities;

[25] Bidders may seek and be granted an extension of their time to cure for good cause, which will be granted in the Commission's discretion.

[26] As to the Coordination Agreement, the Commission will consider the manner and extent to which the Project mitigates Component on Component risk for ratepayers (i.e., the risk that either the Generation Component or the Transmission Component is delayed or not completed or otherwise unable to meet its contract obligations). To the extent the Commission reviews standalone bids, it will examine the proposed coordination agreement, including if and how it could be paired with a complementary component.

[27] Redlines are strongly discouraged and will not be accepted without good cause. When reviewing redlines, the Commission will consider the extent the proposed changes would transfer risks and costs to ratepayers and / or materially change the contemplated commercial arrangement.

k) Any other ratepayer benefits identified by the bidder that Commission deems appropriate to consider; and

l) Previous experience of the Commission or any of the Coordinating States with the bidder.

In the third and final stage, the Commission will review the pricing package of the Generation Component and the cost estimates and containment mechanisms for the Transmission Component. The evaluation of Price and the evaluation of Cost are set forth in detail below. This stage of review will involve an assessment of factors such as the benefits of price suppression, the reasonableness of cost estimates and price caps, the strength of cost containment mechanisms, and any other factors impacting price.

4.1 Proposal Viability

At minimum, the viability of a project will be based on:

a) A comprehensive project schedule that demonstrates how the Generation Component and Transmission Component will achieve the proposed respective commercial operation dates, and completion of the entire Project;

b) Ability for complementary components to work together to manage risk and timelines or, for standalone bids, the ability to successfully be paired with developer(s) of the complementary component;

c) Demonstration of the likelihood of timely development, including regulatory processes and approvals and Project development and financing related factors;

d) Demonstration of site control, including the use of existing corridors and rights-of-way, control of any required rights-of-way or parcels of land, and credible plans to acquire site control where not already acquired;

e) Community engagement plans;

f) Utilization of equipment that is commercially available now or that can reasonably be expected to be commercially available and can be procured and delivered in time to construct the Project components; and

g) Assessment of the project's risks, including likelihood of occurrence and impact on the project, treatment of these risks, who owns the risk, and any residual risk remaining after treatment.

4.2 Technical and Financial Qualifications

Technical and financial qualifications of the bidder and related project development entities will be evaluated based, at minimum, on its demonstration of the feasibility of

obtaining debt and equity financing to develop the projects and bring them into commercial operation. Bidders with a track record of securing lending for transmission and generation projects are preferable. Preference will be given to projects with equity investors with the financial ability to make the required equity injections.

4.3 Bidder Qualifications

At minimum, bidder qualifications will be assessed based on:

a) Demonstration of project management experience and expertise to design, develop, finance, construct and operate projects of the same or similar technology and similar size to what is being proposed;

b) Demonstration of a thorough understanding of the requirements and a realistic plan for securing necessary approvals from FERC, ISO-NE, and the applicable states; and

c) Demonstration of a thorough understanding of the requirements and a realistic plan for securing necessary permits, approvals, and authorizations from applicable federal, state, and local authorities required to develop, construct, and operate projects of the same or similar technology and similar size to what is being proposed.

4.4 Economic Benefits

In Stage Two of the evaluation, bidders will be evaluated on the direct, measurable, and tangible benefits their proposals would provide to Northern Maine, which may include but are not limited to jobs, investment in host communities, and tax payments. Bidders should also identify and quantify direct benefits that would accrue to any of the other Coordinating States.

Additionally, the Commission will review proposals to determine whether they maximize benefits to Maine in accordance with 35-A M.R.S. § 3201-I. Methods of showing a maximization of benefits include, but are not limited to, comparisons of the proposed prices of energy and RECs under the PPA to forecast market prices, impacts on locational market pricing, impacts on the costs of capacity and ancillary services, improvements in supply and system reliability, and reductions in congestion costs.

4.5 Preferences

35-A M.R.S. §§ 3210-I(2)(C) and (3)(D) sets forth that a preference will be given to projects that:

a) In the Commission's determination, demonstrate the most cost effective and efficient transmission access to and development of renewable energy

resources in Northern Maine in a manner that best supports the achievement of the State's renewable energy goals under 3210 and that maximize benefits to the State;

b) Only to the extent available at the time proposals are submitted, maximize the use of federal tax credits[28] by including agreements described in 29 United States Code, Section 158(f) and by committing to entering into an employer and employee harmony agreement with a labor organization seeking to represent the project's operation and maintenance workers. An employer and employee harmony agreement must bind all contractors and subcontractors, other than employees who work on a temporary basis for the employer, to the terms of the agreement. The agreement must be designed to ensure that all work on the energy generation project, including but not limited to work performed in the manufacturing, fabrication or maintenance of the project or operations associated with the project, is uninterrupted, prompt and safe.

In addition to the above, the following preferences also apply to the Transmission Component:

a) Proposals that provide community engagement plans and favor use, to the extent practicable, of existing utility and other rights-of-way and other existing transmission corridors in the construction of the Transmission Component;

b) Proposals that, in the Commission's determination, are likely to provide a reduction in transmission costs and costs to ratepayers for electricity over time as more energy is transmitted using the Transmission Component; and

c) Proposals that adequately demonstrate project viability within a commercially reasonable time frame.

d) Proposals that enable expandability to achieve objectives of Maine and Coordinating States in excess of 1,200 MW of transmission and associated energy and RECs.

4.6 Evaluation of PPA Price

The evaluation of the PPA price will include:

a) Benefits and costs to ratepayers[29] determined on the basis of the net delivered cost of energy and Renewable Energy Credits.

[28] Bidders should not assume the availability of the Investment Tax Credit (ITC).

[29] The term "ratepayers" refers to both those in Maine and those served or represented by the other coordinating states.

b) The bid's proposed cap on price;

c) Total price, including costs to ratepayers and any other costs associated with the proposal(s), including evaluation of risks of potential for increases in those costs due to changes in law, casualty events, or other impacts on the project.

d) Cost-effectiveness including the degree to which the proposals minimize the delivered cost of energy and balance the objectives of (1) maximizing throughput on the Transmission Component and (2) minimizing curtailed energy.

e) Value to ratepayers provided by each Generation Facility in the Generation Component including but not limited to:

(i) Projected market value of contracted products;

(ii) Locational value and effects related to delivery of products;

(iii) Other ratepayer benefits.

4.7 Evaluation of Cost of Transmission Component

The evaluation of the cost of the Transmission Component will include:

a) Benefits and costs to ratepayers.[30]

b) Demonstrated reasonableness of the Transmission Component cost estimates.

c) Total cost, including costs to ratepayers and any other costs associated with the proposal(s), including evaluation of risks of potential for increases in those costs due to changes in law, casualty events, or other impacts on the project.

d) Cost-effectiveness including the degree to which the proposals minimize the delivered cost of energy and balance the objectives of: (1) maximizing throughput on the Transmission Component; and (2) minimizing curtailed energy.

e) Value to ratepayers provided by each of the Generation Component and Transmission Component, including but not limited to:

(i) Amount and nature of transmission capacity, including availability of transmission capacity; and

[30] The term "ratepayers" refers to both those in Maine and those served or represented by the other Coordinating States.

(ii) Other ratepayer benefits.

f) Cost management provisions for the Transmission Component, including mitigation of the impact on ratepayers of cost overruns, delays, and Transmission Component outages.

5. PROPOSAL CONTENT

Joint proposals should be broken into three parts:

1) a general overview of the Proposal and information relating to the Proposal as a whole, including a Coordination Agreement among the developers of the Transmission and Generation Components;

2) specific information relating to the Generation Component; and

3) specific information relating to the Transmission Component.

Standalone proposals for only one component must be broken into two parts: (1) a general overview of the proposal, including how it may pair with the complementary component and a proposed term sheet of a Coordination Agreement; and (2) specific information relating to the relevant component.

Proposals should comply with the requirements regarding contents and structure set forth in Sections 5.1-5.4.

5.1 General Overview

Proposals must include a narrative providing a general overview of the Project as a whole. The narrative should identify each bidder included in the proposal, lead team members, other business entities that will be participating in the in the project, and the relationship among the bidders and other business entities. The overview should also include:

- The expected commercial operations date;
- The expected annual MWh delivered by the Project;
- A brief description of the proposed transmission facility, including start and end locations, the facility's scope of work, capacity, route, and design; and
- A brief description of the proposed generation facility(ies), including resource types, locations, installed capacity, capacity factors, and each facility's scope of work.

5.2 Coordination Agreement

Proposals must include a term sheet reflecting the agreed upon (for joint bids) or proposed (for standalone bids) terms to be included in the Coordination Agreement between the Transmission Component and Generation Component developers.[31] The Coordination Agreement must address the following aspects of the relationship between the developers participating the Project (the Project Members):

a) Roles and Responsibilities – Delineate the roles and responsibilities of the developer responsible for each Project component, along with their respective obligations.

b) Governance – Describe how the development, construction, and operation of the Project will be managed.

c) Construction Coordination – Describe how the Project Members plan to coordinate the construction of the Generation Component and the Transmission Component such that the Generation Component can connect to the Transmission Component and commence the delivery of energy once the Generation Component is completed. The interface risk between the Transmission Component work package and the Generation Component work packages needs to be addressed along with which party owns and manages this risk and how the risk will be mitigated.

d) Interconnection – Describe how the Generation Component will be interconnected with the Transmission Project.

e) Transmission Project Operation – The Project Members must demonstrate how the Transmission Component will be operated after it is brought into service. This includes, to the extent permissible by ISO-NE, coordinating maintenance outages and access to the Transmission Component. The Coordination Agreement must establish the maximum duration of individual and cumulative annual planned transmission outages.

f) Generation Projects Operation – The Project Members must demonstrate how the Generation Component(s) will be operated after they are brought into service. This includes operation of any storage facilities included in the bid to maximize line usage and minimize delivered energy cost. Electric utilities that are party to the PPAs as buyers will not be expected to dispatch or otherwise manage storage.

g) Dispute Resolution – Describe how the Project Members will resolve disputes in a timely manner such that the overall Project is not delayed.

[31] To provide additional time for negotiation, the term sheet for Joint Bids may be submitted on or before April 1, 2026. For standalone proposals, the term sheet should be submitted at the time the bid is submitted.

h) Liability – Describe each Project Members' liability towards the other in the event of a failure to perform or other breach of the Coordination Agreement and how this will mitigate the effect of such breach on the ratepayers of the Coordinating States.

i) Project Milestones – Provide the agreed upon milestones for the development and construction of each of the Project's components, with the date that each milestone must be achieved by and the developer responsible for the milestone deliverable. The Coordination Agreement must describe how coordination will be ensured, how delays of each component and the Project overall will be addressed and each developer's liability to the others if the component they are responsible for cannot be developed or constructed on schedule. At a minimum, these milestones are expected to include:

   (i) FERC approval of Section 205 filing effectuating the VA term sheet;
   (ii) Receipt of all required permits;
   (iii) Execution of the Large Generator Interconnection Agreement(s), Elective Transmission Upgrade Interconnection Agreement, and other regulatory arrangements as outlined in ISO-NE Schedule 25;
   (iv) Ordering of major equipment and other components;
   (v) Final investment decision for each of the Project Members;
   (vi) Issuance of Notice to Proceed for each Project Component; and
   (vii) Commercial operation date.

j) Stakeholder and Community Engagement – Describe how the Project Members will coordinate their outreach to stakeholders and impacted communities in a manner to ensure that information sharing is consistent and that stakeholders, impacted communities, and other interested parties are informed of the scope and progress of the overall Project.

k) Commercial Operation – Acknowledge that the Generation Component will not be considered to reach commercial operation until the Transmission Component is placed in service.

The milestones developed under the Coordination Agreement must allow the Commission and any coordinating states to monitor the development, permitting, and construction phases of each component of the Project and determine if the overall Project will reach commercial operation as scheduled.

5.3 Component-Specific Information

Specific information relating to the Generation or Transmission Component must include a description of the proposed project, information required to demonstrate the eligibility, viability, claimed benefits of the facility, and other required information and documentation set forth in this RFP.

Proposals for each component must be organized in the order set forth in Appendix E (Generation Component) and Appendix D (Transmission Component) with section numbers that correspond to the numeration in the applicable appendix. For example, the Executive Summary must be Section 1 of the proposal.

Proposals must be submitted as a searchable PDF file with numbered pages.

5.4 Proposal Security Deposits

Each proposal must be accompanied by a Proposal Security Deposit equal to the applicable amount below:

- Transmission: $100,000
- Generation: the lesser of $5 per kW nameplate capacity of the project or $100,000.

Deposits should be submitted directly to the Maine transmission and distribution utility designated in the instructions. The Proposal Security Deposit must be in the form of cash (U.S. currency) or an irrevocable, transferable and unconditional standby letter of credit issued by a U.S. commercial bank or a foreign bank with a U.S. branch with such bank having a minimum credit rating of A- from S&P or A3 from Moody's. Deposits provided in cash will be held in an interest-bearing escrow account. The Proposal Security Deposit will: (1) be refunded if a proposal is not selected; (2) for the selected generator(s), be replaced with Performance Security; or (3) for the selected transmission developer, be returned upon execution of the VA Term Sheet.

Instructions for submitting security deposits are provided in Appendix N.

6. MISCELLANEOUS

6.1 Binding Proposals

Proposals are binding on the Bidders and must be submitted in accordance with this RFP or as otherwise specified by the Commission. The Commission reserves the right to seek clarification or request additional information, documentation, and other materials related to the proposals on its own behalf or on behalf of any coordinating state or entity. Failure to provide any such items within the timeframe requested may result in disqualification.

6.2 Confidential and Proprietary Information

A bidder may designate information included in its proposal as confidential proprietary information or critical energy infrastructure information. The Commission and the Coordinating States will take every reasonable step, consistent with law, to protect information that is clearly identified as proprietary or confidential on the page on which it appears. By submitting a proposal, bidders consent to the sharing of protected confidential information with all Coordinating States, procuring entities, representatives from ISO-NE, and other federal, regional, state, or local governmental or regulatory entities, as determined to be necessary by the Coordinating States and under appropriate protections.

The Commission and its Staff, and the Coordinating States and their staff and employees, will not be required to sign any non-disclosure agreements supplied by bidders.

The identity of bidders whose proposals receive an award and information about the awarded proposals will ultimately be made public, including the contracts, term sheets, expected location of the facilities included in their proposal, and associated price.

6.3 Proposal Costs

All costs associated with developing and submitting a proposal in response to this RFP and providing oral or written clarification of its contents as well as negotiating a PPA, VA, or other required contracts or agreements, shall be borne entirely by the bidder(s).

6.4 Rights of the Commission

The Commission may accept or reject any proposal or reject all proposals based on its assessment of whether a proposal meets the requirements of the RFP, satisfies the applicable statutory policies and objectives, conforms with generally accepted business practices, and determines it is or is not within the contracting authority of the Commission. In its discretion, the Commission may request modifications to

proposals, provide bidders an opportunity to correct non-conforming bids, or request a refresh of bids.

The Commission reserves the right to withdraw or modify the RFP at any time for any reason. If the Commission determines that no proposal would produce a contract that would be in the public interest, it may terminate this bidding process.

Any award made in accordance with this RFP will be determined by the Commission to be consistent with applicable laws and rules, the provisions of this RFP, and the Commission's statutory public interest obligations. The Commission may cancel any award before the approval of an executed PPA or term sheet attached to the VA.[32]

The Commission reserves the right to reject any proposal that makes material changes to the model PPA or VA other than those modifications specifically authorized in this RFP.

6.5 Limit of Liability

The State of Maine, its officers, agents, and employees, including the Maine Public Utilities Commission, its Commissioners, employees, agents, and any other coordinating state or entity and its officers, agents, and employees shall not be responsible or liable in any manner for risks, costs, expenses, or other damages incurred by any bidder or other entity involved, directly or indirectly, with this RFP.

The State of Maine, its officers, agents, and employees, including the Maine Public Utilities Commission, its Commissioners, employees, agents, consultants and any other coordinating state or entity and its officers, agents, and employees shall be held harmless from any and all claims, costs, expenses, injuries, liabilities, losses, and damages of any kind resulting from, directly or indirectly, this RFP.

6.6 Warranty

The information contained in the RFP and subsequently provided materials is prepared to assist bidders and does not purport to contain all of the information that may be relevant to bidders or the Commission. The Commission and the other Coordinating States and entities make no representation or warranty, expressed or implied, as to the accuracy or completeness of the information. The Commission, its Staff, its agents, and any other Coordinating States or entities are not liable for any representations, expressed or implied in, or any omissions from, this RFP and subsequently provided materials. The same applies to any information obtained by bidders from the Commission, its Staff, its agents, its consultants, the other Coordinating States and entities, or any other source.

[32] Bidders should also be prepared that any of the coordinating entities or states may also reserve and exercise their own ability to cancel any award prior to the execution of their PPAs or the term sheet attached to the Voluntary Agreement.