CENTRAL MAINE POWER COMPANY
SUPPLEMENTAL RESPONSE TO EXAMINER'S DATA REQUEST NO. 2
DOCKET No. 2008-255

September 29, 2009

EX-02-28 (Supplemental)

Q. (Volume I, Page 60, Lines 10-11). Please affirm your expectation that almost all MPRP has been designated as PTF and the costs regionalized. Please supply any cost cap based on the PTF designation. If such a determination has not yet been made, please provide an update on the status of such a determination.

A. On September 24, 2009, ISO-NE posted the attached draft TCA determination letter on its web site and will be circulating it to the NEPOOL Reliability Committee and ISO Planning Advisory Committee (PAC) for a 30-day comment period before a final formal transmittal to CMP. As explained in the TCA determination letter, ISO-NE approved $1,376 million of the costs of MPRP for inclusion in New England-wide Regional Network Service (RNS) rates. This represents all of the estimated costs of MPRP except 1) those related to Section 254 from Orrington to Coopers Mills, for which CMP has not yet sought cost recovery because of the pending determination as to the design specifications for that line, and 2) approximately $40 million of costs, which CMP identified as "Localized Costs" under the terms of the ISO-NE tariff since they do not qualify as PTF. This means that ISO-NE agrees with CMP that MPRP constitutes a regional "Reliability Transmission Upgrade" under the ISO-NE tariff, which should be socialized according to the RNS rates. As a result, CMP's customers will be responsible for only about 7% of the costs of MPRP.

Subject to any comments ISO-NE receives during the 30-day comment period, this TCA determination completes the process of determining the cost recovery of MPRP under the regional tariff, with only Section 254 cost recovery remaining to be determined. CMP will pursue a TCA determination for Section 254 once ISO-NE issues a recommendation letter regarding the construction of that section to 345 kV or 115 kV standards.

The TCA application filed by CMP is available at the ISO-NE website (http://www.iso-ne.com/committees/comm_wkgrps/relblty_comm/relblty/ceii/ceii_mtrls/2009/jan262009/mprp_tca_cmp_09_tca_01.pdf). The TCA Application is voluminous, contains Critical Energy Infrastructure Information or "CEII" and is password protected. Access to the document can be obtained by contacting ISO Customer Service at custserv@iso-ne.com.

Response Prepared and Submitted By:
David Conroy
Manager of System Planning

Attachment(s):
1. ISO-NE Draft Determination Letter (Sept. 24, 2009)
2. Attachment 1 to ISO-NE Draft Determination Letter (Sept. 24, 2009)

DRAFT DETERMINATION FOR COMMENT

ISO new england

September 24, 2009

Mr. David M. Conroy
Central Maine Power Company
83 Edison Drive
Augusta, Maine 04336
Tel: 207-626-9750

Re: TCA Application CMP-09-TCA-01: Request for Pool-Supported PTF Cost Treatment for Maine Power Reliability Program; ISO New England Written Findings and Determination

Dear Mr. Conroy:

This letter provides the determination of ISO New England Inc. (the "ISO") in connection with the transmission cost allocation application dated January 15, 2009 and revised on May 19, 2009 (the "Application")[1] submitted by the Central Maine Power Company ("CMP") pursuant to Schedule 12C of Part II of the ISO New England, Inc. ("ISO") Transmission, Markets and Services Tariff[2] and ISO Planning Procedure 4 ("PP-4").[3]

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[1] The total Application submitted by CMP is just under 2,400 pages in length. Due to its size, the Application is not included as an exhibit to this letter, but is posted on the ISO's website at http://www.iso-ne.com/committees/comm_wkgrps/relblty_comm/relblty/ceii/ceii_mtrls/2009/jan262009/mprp_tca_cmp_09_tca_01.pdf The TCA Application contains Critical Energy Infrastructure Information or "CEII" and is password protected. Access to the document can be obtained by contacting ISO Customer Service at custserv@iso-ne.com.

[2] The ISO Transmission, Markets and Services Tariff, FERC Electric Tariff No. 3 ("ISO Tariff").

[3] Capitalized terms not defined in this determination have the meanings ascribed thereto in the ISO Tariff, the Second Restated New England Power Pool Agreement, and the Participants Agreement.

The Application under review involves the costs associated with the construction of 192 miles of new 345 kV transmission circuits, 75 miles of new 115 kV transmission circuits, and 20 substation projects (collectively the "Maine Power Reliability Program," "MPRP" or the "Project"). This Project's proposed facilities are to be constructed in a number of different locations throughout the state of Maine and provide needed reliability improvements to the New England Transmission System. The scope of the Project incorporates the addition of new 345 and 115 kV circuits coupled with the rebuilding, rerating, and reconfiguration of numerous existing facilities. The most significant system upgrades planned under the Application are for the addition of new 345 kV transmission lines which effectively create a new 345 kV path between Orrington and Three Rivers stations. New autotransformers are planned at Albion Rd, Larrabee Road, Raven Farm, South Gorham and Maguire Road. The Project also includes a new 115 kV line between Orrington and Coopers Mills (previously referred to as Maxcys), a new 115 kV transmission line between Coopers Mills and Highland Substations, a new line between Larrabee Road and Lewiston Lower, and in western Maine, a new 115 kV transmission line between Rumford IP and Larrabee Road Substation. The project has a proposed in-service date of late 2012.

I. SUMMARY OF THE ISO DETERMINATION

As explained in this determination letter, the ISO finds that $1,375,904,000 of the $1,375,904,000 requested by CMP are properly categorized as Pool-Supported PTF Costs under Schedule 12C of the ISO Tariff.

II. OVERVIEW OF SCHEDULE 12C

As described in greater detail below, the MPRP was developed in the New England planning process in order to address significant reliability issues on the transmission system. The project is rated at 115 kV and above, meets the non-voltage criteria for PTF, and is included in the Regional System Plan as a Reliability Transmission Upgrade.[4] The costs of the MPRP therefore qualify for treatment as Pool Supported PTF costs, subject to the identification of Localized Costs pursuant to the ISO Tariff.[5]

The ISO's role in determining Localized Costs is defined by Schedules 12 and 12C, and PP-4. Schedule 12 of the Tariff requires the ISO to review Regional Benefit

[4] These are the elements of a "Regional Benefit Upgrade" as listed at Section 1.119, Section II of the ISO Tariff.

[5] *See* Section 7, Schedule 12, Part II of the ISO Tariff (ISO required to review Regional Benefit Upgrades pursuant to Schedule 12C).

Upgrades and identify any Localized Costs associated with them, noting that Localized Costs "shall not be included in the Pool-Supported PTF costs recoverable under this OATT . . . ."[6] Schedule 12C provides that "[t]he ISO shall determine what those reasonable requirements are that are consistent with Good Utility Practice and the current engineering design and construction practices in the area in which the Transmission Upgrade is built [and that] [t]he costs of Transmission Upgrades that exceed those reasonable requirements . . . shall be deemed Localized Costs."[7]

In discussing the factors the ISO must consider when making its determination of whether Localized Costs exist, Schedule 12C and Planning Procedure No. 4 provide that, with advisory input from the Reliability Committee, the ISO will consider the reasonableness of the proposed design and construction method with respect to:

a) Good Utility Practice;

b) current engineering design and construction practices in the area in which the Project is proposed to be built/is being built;

c) allowing for appropriate expansion and load growth;

d) alternate feasible and practical transmission alternatives; and

e) the relative costs, operation, efficiency, reliability and timing of implementation of the proposed Project.

Section II of the ISO Tariff utilizes the following definition for Good Utility Practice:

> Any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather includes all acceptable

6 *Id.*

7 Section 1, Schedule 12C, Part II of the ISO Tariff.

> practices, methods, or acts generally accepted in the region.[8]

PP-4 also clarifies that a "feasible and practical transmission alternative means a transmission alternative that is feasible and practical from an *engineering design and construction perspective*."[9] Also, "[a]n alternative that is not or may not be approved by a siting or local review board may still be considered a feasible and practical transmission alternative[.]"[10] The ISO will consider an "[a]ssessment of the schedule or in-service date of the Project *from an engineering and construction* standpoint rather than from the standpoint of potential delays in local or state siting."[11]

Attachment A to PP-4 also provides guidance regarding Localized Costs. Included in Attachment A is non-exclusive list of examples illustrating the portions of a Project that may be considered Localized Costs.[12]

In other words, Schedule 12C directs the ISO to determine whether the estimated costs of a proposed project exceed the estimated costs of an alternative project that provides similar performance and that is consistent with Good Utility Practice and feasible and practical to be designed and constructed from an engineering standpoint. The fact that it may be difficult or impossible from a state or local statutory, regulatory, or political perspective to convince a relevant governmental body to allow the applicant to build such an alternative is irrelevant, because this outcome would be unrelated to engineering design and construction or Good Utility Practice issues.

The ISO's determination of Localized Costs is based primarily on the types of expenditures proposed. Such cost estimates are relevant to the ISO, not for ratemaking purposes, but rather for determining the presence of Localized Costs by analyzing, for example, whether a project will cost more than a transmission alternative with similarly robust power system performance. However, an ISO finding that certain proposed expenses do not constitute Localized Costs should in no way be interpreted as a determination by the ISO that such estimates are accurate and should automatically be included in the regional transmission revenue requirement collected by Participating Transmission Owners ("PTOs") through Attachment F of Section II of the ISO Tariff, since that revenue requirement is based on actual costs (either already incurred or forecasted but trued-up, with interest). The PTOs are responsible for including the proper

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[8] Section 1.35, Section II of the ISO Tariff.

[9] PP-4 § 1.6.1(d)(i) (emphasis added).

[10] *Id.* (emphasis added).

[11] PP-4, Attachment A (emphasis added).

[12] As previously noted, Attachment A to PP-4 makes clear that "all relevant costs" would not include "potential delays in local or state siting."

supporting information and detail in their annual informational filing as required by Attachment F and its Implementation Rule. An ISO finding of Localized Costs does not prohibit a PTO from seeking to include such expenditures in its rates for Local Service under Schedule 21 of the Tariff.

In addition, the ISO's determination that certain costs do not constitute Localized Costs is not, and should not be interpreted as a finding with regard to the prudence of those costs.[13] The review and determination of prudence of a given cost is an area subject to regulatory review by the Federal Energy Regulatory Commission ("FERC" or the "Commission").[14]

III. OVERVIEW OF THE DEVELOPMENT OF THE PROJECT THROUGH THE REGIONAL PLANNING PROCESS AND SUMMARY OF THE MPRP PROJECT

A. Identification of Reliability Issues and Development of the MPRP Solution Through the Regional Planning Process

In order to qualify for regional cost treatment under the ISO Tariff as a Regional Benefit Upgrade, a project must meet an identified reliability need on the transmission system and be included in the Regional System Plan ("RSP").[15] A brief review of the regional planning process and the development of MPRP through that process is included in this determination.

ISO New England is the independent, not-for-profit Regional Transmission Organization[16] and the federally-authorized planning authority for the electric

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[13] The Federal Power Act allows public utilities to exercise broad discretion in incurring costs necessary to serve their customers. The test is whether the expenditures "are costs which a reasonable utility management (or that of another jurisdictional entity) would have made, in good faith, under the same circumstances, and at the relevant point in time." *New England Power Co.*, 31 FERC ¶ 61,047 at p. 61,084 (1985), *aff'd sub nom. Violet v. FERC*, 800 F.2d 280 (1st Cir. 1986). The public utility is presumed to have acted prudently, "absent a showing of inefficiency or improvidence." *Id.* at p. 61,082.

[14] *Id.* at p. 61,084 (noting that it is the Commission's duty to determine the prudence of a public utility's challenged expenditures).

[15] *See* Section 1.119, Section II, ISO Tariff. As discussed later in this determination, a project must also be approved under the Proposed Plan Application reliability review process under Section 3.9 of the Section I of the ISO Tariff.

[16] *ISO New England Inc.*, 110 FERC ¶ 61,111 (2005) (authorizing RTO operations).

transmission system in the New England Control Area.[17] The ISO conducts its planning process pursuant to Attachment K[18] of Section II of the ISO Tariff.[19]

The regional system planning process is designed to ensure the reliability of the New England Transmission System and compliance with national and regional planning standards, criteria and procedures, while accounting for market performance and economic, environmental and other considerations, as may be agreed upon from time to time.[20] The RSP produced as a part of the regional system planning process is based on a five- to ten-year planning horizon, and reflects five-to-ten-year capacity and load forecasts.

As part of the regional system planning process, the ISO undertakes assessments – in coordination with the PTOs and the Planning Advisory Committee ("PAC")[21] – of the needs of the PTF system on a system-wide or specific area basis, defined in Attachment K as "Needs Assessments." Needs Assessments analyze the adequacy of the PTF system, as a whole or in part, to maintain the reliability of such facilities while promoting the operation of efficient wholesale electric markets in New England. For the development of the Needs Assessments, the ISO may form a targeted study group of

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[17] *ISO New England Inc.& New England Power Pool, Order on Reh'g Requests and Compliance Filings*, 95 FERC ¶ 61,348 (2001) (authorizing the ISO to oversee regional transmission planning). With regard to the ISO's authority to review and approve proposed changes to the system on a technical basis, *see New England Power Pool and ISO New England Inc.*, Order Accepting Compliance Filing, 103 FERC ¶ 61,304 (2003) ("[ISO] is the appropriate authority to approve planning for transmission upgrades and changes to supply and demand-side resources.").

[18] The ISO created its Attachment K planning procedures in compliance with *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, FERC Stats. & Regs. ¶ 31,241, at P 893 ("Order No. 890"), *order on reh'g*, Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 126 FERC ¶ 61,228 (2009). *See ISO New England Inc.*, 123 FERC ¶ 61,161 (2008) (accepting the ISO's Attachment K filing, subject to further compliance filings).

[19] Prior to the implementation of Attachment K in compliance with Order No. 890, the ISO conducted its planning process in accordance with Section 48 of Section II of the ISO Tariff. The text's description of the regional system planning process is taken from Attachment K, and has the same general approach as was utilized in Section 48.

[20] Section 1, Attachment K, Section II of the ISO Tariff.

[21] To ensure that the ISO receives the full benefit of input from all interested stakeholder, the ISO convenes multiple planning meetings over the course of a year with the PAC, which is a stakeholder group that is open to any interested entity, including but not limited to: Transmission Customers, Market Participants, and representatives of the New England states, including regulators. A description of the PAC is provided at Section 2, Attachment K, Section II of the ISO Tariff.

representatives of affected stakeholders based on the scope of the particular Needs Assessment. The PAC provides input on the scope, assumptions and procedures of the Needs Assessment. Generally, following a Needs Assessment, the ISO will evaluate the adequacy of proposed regulated solutions by performing Solutions Studies.[22]

With regard to the development of MPRP, system weaknesses were highlighted in the 2006 RSP.[23] A study group was formed to assist in development of the Needs Assessment for the Maine portion of the New England Transmission System.[24] That study group consisted of CMP in coordination with Bangor Hydro-Electric Co., Maine Public Service Co., the Northern Maine Independent System Administrator and Northeast Utilities, under the direction and supervision of the ISO.[25] To evaluate the reliability of the Maine-area transmission system with regard to steady-state thermal and voltage needs, CMP engaged RLC Engineering, Inc. ("RLC").[26]

The study group scoped and performed a deterministic planning analysis for eighteen different operating scenarios, approximately 275 NERC Category B and C contingencies, and basic transmission reliability criteria for the transmission system.[27] This work resulted in the Needs Assessment.[28]

The Needs Assessment identified several significant reliability issues,[29] noted that other problems may exist that could not be identified because they were masked by the

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[22] The ISO incorporates market responses that have met specified criteria into the Needs Assessments or RSP. Where market responses incorporated into the Needs Assessments do not eliminate or address the needs identified by the ISO in Needs Assessments or the RSP, the ISO develops or evaluates regulated transmission solutions proposed in response to the needs identified by the ISO. *See* Section 1, Attachment K, Section II of the ISO Tariff.

[23] *See* RSP 2006 at p. 8: "Several areas of Maine and New Hampshire have serious reliability issues. The transmission improvement studies for northern New England will identify projects that will resolve these issues. These studies will also identify upgrades that will increase the transfer capabilities of the northern New England interfaces and simplify the operation of the system." http://www.iso-ne.com/trans/sys_studies/rsp_docs/rpts/2006/rsp06_final.pdf

[24] Application at 1.

[25] *Id.*

[26] *Id.* at 8.

[27] *Id.*

[28] The Needs Assessment was included as Attachment A to the Application. http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/reports/2007/index.html

[29] The study results indicated significant reliability issues upon the occurrence of different contingencies, including the loss of load in a significant portion of Maine, and excessive thermal (continued...)

severity of the problems on the Maine transmission system,[30] and indicated the following summary of transmission system needs:

1. Insufficient 345 kV transmission;
2. Insufficient 345 /115 kV transformation capability;
3. Insufficient 345 kV transmission support for Portland and the southern region;
4. Insufficient transmission infrastructure in western, central, and southern Maine regions;
5. Insufficient transmission infrastructure in the Mid-coast and Downeast Maine regions; and
6. Insufficient thermal capacity ratings of the transmission lines.[31]

Information regarding the Needs Assessment study was reviewed with the PAC at the March 13 and May 16, 2007 meetings. A final version of the Needs Assessment was released by RLC Engineering on June 19, 2007. Those system needs were identified in the 2007 RSP.[32]

(...continued)
overloads and voltage collapse of the entire region. *See* Application at pp. 8-11. In some cases, the identified problems at N-1 were so severe that portions of conceptual fixes needed to be added to the system under study in order to even study N-1-1 events.

[30] For example, the Needs Assessment study document states that, after reviewing several post-contingency thermal overload issues that were "unrelated to particular dispatch conditions," "[t]here may be additional deficiencies or violations of reliability criteria that were not uncovered by the Needs Assessment due to inadequacies of Maine's bulk power transmission system. These inadequacies were masked by voltage collapse or failure to solve the powerflow simulation used to perform the reliability baseline evaluation on many critical contingencies." Needs Assessment at p. iv. Elsewhere the Needs Assessment found such "severe weakness" of the transmission system in some of the N-1 studies that the usual N-1-1 studies were not performed in some cases because such studies "would have been redundant and not provided additional useful detail." *See* Needs Assessment at pp. 26 and 36 ("...the N-1-1 analysis was not performed after the transmission system demonstrated such poor performance following the N-1 contingency.")

[31] The significant system reliability issues associated with these deficiencies are summarized at pp. 8-11 of the Application.

[32] http://www.iso-ne.com/trans/sys_studies/rsp_docs/rpts/2007/rsp07_final_101907.pdf at p. 81.

Following the completion of the Needs Assessment, an analysis of possible transmission alternatives was undertaken by CMP. This work resulted in the Transmission Alternatives Assessment. That assessment analyzed both 345 kV and 115 kV expansion alternatives.[33] The alternatives were selected initially based on the likely availability of corridors for new transmission construction and on the potential expandability of existing substations.[34] Five different configurations were considered as solutions for the transmission system north of Surowiec and five different configurations were considered for the system south of Surowiec.[35]

In the southern portion of the system, CMP identified a solution denominated as the S1 Elm alternative as superior to other alternatives, stating:

> In the southern portion of the system, the S1 Elm alternative was superior to all other transmission alternatives evaluated. This solution had lower costs and superior performance than all other configurations analyzed. The S1 Elm transmission alternative also had lower costs and better performance than any of the non-transmission alternatives… .[36]

CMP notes in its Application that it is not seeking TCA cost recovery at this time for the 115 kV line from Elm Street to East Deering to Cape substation.

In the northern portion of the system, CMP identified the transmission solution that it denominated as N5 as the preferred alternative over other transmission solutions and other non-transmission alternatives that CMP also considered.[37] As CMP notes in its Application:

> In the northern portion of the system, the N5 transmission solution was selected over the other alternative transmission solutions and over the non-transmission alternatives. N5 did have higher costs (see following tables) [tables omitted] than certain other transmission solutions, but the N5 transmission solution had superior electrical performance, higher loss savings, greater transfer capability and better longevity. [38]

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[33] Application at p. 12.

[34] *Id.*

[35] *Id.*

[36] *Id.*

[37] Application at p. 13.

[38] *Id.*

The Transmission Alternatives Assessment was reviewed with the PAC at meetings held on July 11, 2007, November 8, 2007, and January 17, 2008.

The preferred transmission solution developed through the Transmission Alternatives Assessment consists of the elements described in the construction sequencing document included by CMP as part of its Application and excerpted and attached to this determination as Attachment 1.

B. The Proposed Plan Applications for MPRP

Under the terms of Schedule 12C, proponents of transmission projects that are determined to be needed for reliability reasons must complete the Proposed Plan Application process set out in Section 3.9 of Part I of the ISO Tariff prior to submitting a TCA Application for regional cost recovery. This process provides for a review of proposed changes to the transmission system to determine if the proposed plan will have any adverse impact on the transmission system.

CMP presented 36 Transmission Facilities Proposed Plan Applications ("PPAs"), along with three Transmission Facility Proposed Plan Applications submitted by Northeast Utilities at the June 17, 2009 meeting of the NEPOOL Reliability Committee.[39] The applications represented the components of the MPRP and were submitted with an expected in-service date of June 2012. The Reliability Committee provided advisory input to the ISO regarding the PPAs. On July 31, 2008, the ISO issued a letter to CMP and Northeast Utilities indicating that the implementation of their proposed projects would "not have a significant adverse effect on the stability, reliability or operating characteristics" on the transmission system.[40]

In December 2008, CMP and NU submitted revised PPAs to reflect scope changes to the MPRP and a revised in-service date of December 2012.[41] On February 26, 2009, the ISO issued a letter to CMP and Northeast Utilities indicating that

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[39] A copy of the first set of proposed plan applications for MPRP can be viewed at the following URL: http://www.iso-ne.com/committees/comm_wkgrps/relblty_comm/relblty/mtrls/2008/jun172008/index.html.

[40] http://www.iso-ne.com/trans/pp_tca/isone_app_approvals/prop_plan/2008/jul/mprp_cmp-08-t03-thru-t36-and-x01_and_nu-08-t08-thru-t10.pdf.

[41] A copy of the revised proposed plan applications for MPRP can viewed at the following URL: http://www.iso-ne.com/committees/comm_wkgrps/relblty_comm/relblty/mtrls/2009/jan262009/index.html

implementation of the revised plans would not create a significant adverse impact to the transmission system.[42]

IV. FILING OF THE TCA APPLICATION; ISO AND STAKEHOLDER TCA REVIEW

On January 15, 2009, CMP submitted to the ISO its TCA application pursuant to Section 12C of Section II of the ISO Tariff for its portion of the MPRP. The nearly 2,400-page Application provided the information required under Schedule 12C and Attachment N of Section II of the ISO Tariff, as further detailed in Section 1.6.1 of PP-4.

As set out in the Participants Agreement and Schedule 12C of Section II of the ISO Tariff, and as further detailed in PP-4, the NEPOOL Reliability Committee is tasked with providing advisory input to the ISO regarding whether there are elements of a given project that should not be included in the regional network service rate for recovery because the costs are Localized Costs as described in Schedule 12C. The elements of Schedule 12C are described above in Section II of this determination.

CMP presented information regarding the Project and its Application at the follow meetings of the Reliability Committee:

- December 18, 2008 – Overview of project
- January 26, 2009 – First presentation after submission of the Application
- March 17, 2009 – N1 vs. N5 discussion
- April 21, 2009 – General discussion
- May 19, 2009 – Discussion and vote

This review culminated in seeking an advisory vote of the Reliability Committee on May 19, 2009, when CMP requested consideration of the Application less the costs associated with Section 254 (approximately $134,461,000[43]), since certain engineering studies were not yet completed regarding that section of the Project.[44] Section 254 is a 54-mile 115 kV transmission line between Orrington and Coopers Mills substations.[45]

[42] http://www.iso-ne.com/trans/pp_tca/isone_app_approvals/prop_plan/2009/feb/conroy-scarfone-et-al_mprp_revised-cmp-and-nu-ppas.pdf.

[43] Application, Attachment N, at p. 19 (Nominal Dollars)

[44] CMP indicated via an email sent to the ISO on May 8, 2009 that it wanted to withdraw Section 254 from consideration as part of the current TCA. The motion before the Reliability Committee on May 19, 2009 thus excluded that section of the project from the advisory vote regarding Localized Costs.

[45] Where, as per the Application, Section 254 of the proposed Project would be initially operated at 115 kV but constructed for future operation at 345 kV.

(continued...)

As discussed at the meeting, CMP noted that – following the completion of the additional studies for Section 254 – it would file a separate TCA application for that portion of the Project. After discussion of the Project, a motion was made to consider $1,375,904,000 (*i.e.,* the TCA Application's estimated total PTF cost of $1,510,365,000, minus the estimated Section 254 PTF cost of $134,461,000) as Pool-Supported PTF costs.[46] The motion received a vote of 64.36% of the sectors voting in favor, 35.64% opposed and 50 abstentions. Additional motions to identify Localized Costs were not offered.

In the case of major transmission projects, the ISO also holds public TCA meetings. These stakeholder meetings are in addition to the Reliability Committee advisory process and allow for any interested party to attend,[47] ask questions or provide input regarding whether there are any Localized Costs in a given TCA application. The MPRP stakeholder meeting was conducted on January 29, 2009.[48]

V. ISO ANALYSES AND DETERMINATION

In its initial TCA application, CMP explained that the estimated cost of the MPRP is $1.55 billion, including both costs that CMP has determined to be Localized Costs based on its review of the ISO Tariff, and costs that should be included in the Pool Supported PTF RNS rate. Exclusion of the costs identified by CMP as Localized Costs results in a total amount of $1.51 billion for which treatment as Pool-Supported PTF costs is requested. The total $1.55 billion includes $1.539 billion in new and upgraded facilities and $11 million in modifications to existing facilities affected by the short circuit and stability analyses.[49] As noted above, CMP modified its TCA application in

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[46] The estimated non-PTF costs are $39,635,000 (Nominal Dollars) for the construction of Monmouth Substation, Middle Street Substation and other additional projects.

[47] In particular a wide range of state representatives including members of the New England Conference of Public Utility Commissioners, the New England States Committee on Electricity, Attorney General and Governors' office officials across New England are invited to participate in these meetings.

[48] The CMP presentation for that stakeholder meeting can viewed at the following URL: http://www.iso-ne.com/pubs/pubcomm/forums/2009/tca_stakeholder_mtg_jan292009/1_CMP_MPRP_tca_1_29_09.pdf

[49] Application at p. 2.

May 2009 to exclude the costs associated with the line denominated as Section 254, resulting in a total request for Pool-Supported PTF treatment of $1,375,904,000.[50]

In order to determine whether any of the $1,375,904,000 includes any additional Localized Costs that were not identified by CMP, the ISO considered, with advisory input from the Reliability Committee and other stakeholders, the reasonableness of the proposed design and construction method with respect to: Good Utility Practice; current engineering design and construction practices in the area in which the Project is being built; appropriate expansion for load growth; practical and feasible transmission alternatives; and the relative costs, operation, efficiency, reliability and timing of implementation of the proposed Project.[51]

The ISO has reviewed the Application, including the detailed report attached to, and made part of, the Application entitled: "Maine Power Reliability Program, Schedule 12C TCA Application," dated January 15, 2009. Further, the ISO has considered all of the materials distributed by CMP at various Reliability Committee meetings and the January 29, 2009 special stakeholder meeting pertaining to the Project.

To better understand the Project costs and potential areas of Localized Costs, the ISO issued four data request letters to CMP, dated as follows: February 16, 2009, April 16, 2009, May 13, 2009 and July 20, 2009.[52] These data request letters focused on Project cost estimation methodology, Project financing, alternatives considered, overhead pole design, Project design in the Lewiston area, and Section 254 construction, a portion of the MPRP which as noted above was removed by CMP from this TCA application in May 2009.

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[50] A fair amount of attention has been given to the accuracy of cost estimates for transmission projects in New England over the past few years. The ISO has discussed with state regulators, transmission owners and other utilities how cost the accuracy of project cost estimations can be improved. In its TCA, CMP notes that it "is committed to presenting the cost estimate in this TCA application with a high degree of certainty. To achieve this result, after estimating the cost of the project deterministically, CMP modeled the significant program risks and utilized a probabilistic approach to determine the confidence of the MPRP costs coming in at or below the estimate of $1.55 billion. This estimating methodology is explained in Attachment N to this TCA application." Application at p. 29. CMP has not included any costs associated with financing the Project (such as Allowance for Funds Used During Construction ("AFUDC") or Construction Work In Progress ("CWIP")). As such, recovery of financing costs is not being requested at this time by CMP. The ISO understands that CMP may request recovery of those funds related to financing at a later time.

[51] The content and ISO analysis under Section 12C of Section II of the ISO Tariff is described in greater detail at Section II of this determination.

[52] Copies of the ISO's requests and CMP's responses can be found at the following URL: http://www.iso-ne.com/trans/pp_tca/req/mprp/index.html

In progressing through the regional system planning process described above in Section III.A, five alternatives were identified and analyzed for the northern portion of the Project and five alternatives for the southern portion of the Project. CMP followed the elements of the planning process that has been codified as Attachment K of the ISO Tariff and developed and reviewed alternatives through the open PAC process so that they are not appearing for ISO consideration in the Application for the first time. That process allowed CMP to receive comments and questions from the ISO and other regional stakeholders, including from NEPOOL participants and New England state regulators and other state officials on solution alternatives before a solution was selected by CMP. After review of the Needs Assessment and Transmission Alternatives Analysis, the ISO concurred with CMP that the selection of N5 and S1 Elm was the preferred transmission alternative for addressing the identified reliability issues.

As described, above, Alternative N5 does not have the lowest associated cost-to-construct estimate.[53] However, the ISO concurs with CMP's assessment of the superior attributes of Alternate N5.[54] Further, the ISO has determined that Alternative N5 has superior long-term planning attributes, such as better voltage and thermal characteristics, compared with the other alternatives considered. Alternative S1 Elm is both the least-cost and technically superior alternative.

CMP has proposed the adoption of a 345 kV overhead line design standard which would be utilized, as consistently as possible, for the 192 miles of 345 kV transmission lines to be constructed. Similarly, CMP has proposed the adoption of a 115 kV overhead line design standard which would be utilized, as consistently as possible, for the 75 miles of 115 kV transmission lines to be constructed. While adoption of such standards, particularly in the case of the 115 kV lines, may not produce the lowest possible cost for every individual subsection of the Project, the standardization of transmission designs provides the benefits of efficiencies in procurement, construction, and maintenance over the use of less consistent construction and satisfies the criteria under Schedule 12C as Good Utility Practice and common engineering practice in New England. Where the pole design has varied, it has been where the standardized design could not be used because of right-of-way limitations or waterway crossings.

CMP has proposed the installation of a 1.1-mile 115 kV underground cable, to replace an existing 34.5 kV underground cable, in Lewiston, Maine, where the 34.5 kV cable will be abandoned at no additional cost.[55] A proposed overhead alternative was

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[54] *See* discussion under Section III.A of this determination, above.

[55] *See* response ISO-004-03 from CMP dated August 10, 2009: "In addition, the local Lewiston distribution supply will be via new 115/12.47 kV transformers directly served by Middle Street Substation rather than by the 34.5 kV system. There are no costs associated with abandoning the cable." ISO-004-03 dated August 10, 2009.

reviewed with CMP. The cost of the proposed underground cable would be approximately $7,297,000 as compared to the overhead alternative costs of $2,207,531 plus right-of-way expenses. In CMP's judgment, the cost of a corridor needed for right of way, up to 100 feet in width, would exceed $5.8 million, which does not include costs associated with demolition or for profession services related to the acquisition.[56] As discussed in CMP's response to the ISO's May 13, 2009 data request, question 2, "CMP believes that obtaining the necessary real estate for an overhead line will not be cost effective… ." For cost comparison, CMP provided cost data regarding its Middle Street substation site, a leveled building site located within the city limits with no improvements other than being graded and graveled sufficient to serve as an overflow parking area. CMP explained that that this site had appraised and sold for $10.00/square foot.[57] Therefore, the ISO agrees there is no benefit to further consideration of an overhead alternative for the Lewiston segment, since there would not be a cost savings.

In addition, the 1.1 miles of 115 kV underground cable are proposed to be installed along a canal in Lewiston. The ISO made several inquiries with CMP regarding that routing decision and whether using a street routing would be more cost effective. An in-the-street alternative is the longest of all the alternatives and faces the challenges of encountering other utilities, tearing up the road and possible shoring of the trench because of depth.[58] CMP explained that placing HPFF cable in the canal is approximately $1 million cheaper than placing it in the streets.[59] CMP has also informed the ISO that the all-XLPE in-the-street option is approximately $2-2.5 million more than the canal option.[60] In addition, the use of directional drilling was questioned in this area. CMP explained that an open cut would entail more work, and more work to be done by hand because of the other known and unknown utilities in the area. By using directional drilling, CMP will be able to go several feel under other existing utilities and will not have the complications of deep open trenches, such a shoring for worker safety.[61]

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[56] Where it is estimated that a width of 100 feet for 1.1 miles at $10 per square foot would be approximately $5,800,000.
[57] *See* response ISO-003-02 from CMP dated May 14, 2009.

[58] ISO-03-01.pdf dated May 18, 2009.

[59] "A preliminary estimate of cost for the HPFF system in the Lewiston canal is approximately $6.5 million while the HPFF in city streets is approximately $7.5 million." ISO-11-Attachment_3(CMP-09-TCA-01) dated March 13, 2009.

[60] HPFF located in the canal has an approximate cost of $6.5 million while an in-the-street all XLPE option is $8 Million. ISO-11-Attatcment_3(CMP-09-TCA-01) dated March 13, 2009: "….solid dielectricoption in city streets is approximately $8.0 million". ISO-11-Attachment_3 (CMP-09-TCA-01) dated March 13, 2009.

[61] *See* response ISO-03-01 from CMP dated May 18, 2009.

With regard to the "Reserve" category identified in the TCA Application, the ISO followed up with inquiries to CMP as to the intended function of the Reserve category. CMP has explained that the Reserve costs were an element of a more granular breakout of what might otherwise be considered "Contingency" costs. CMP explained that "Reserve" could be used for "quantities of materials, design changes within scope, reasonable but unanticipated environmental conditions, and use of alternate construction techniques."[62] CMP also made it clear that the Reserve category will not be used for "changes in scope, relocation of portions of the Program and extreme environmental or regulatory conditions."[63] Therefore, the ISO understands from CMP that this category is a form of Contingency. As is the case with contingency costs in any TCA application, the amounts approved may only be utilized for contingencies that would not be considered Localized Costs, and use of the funds for costs that would not qualify for regional cost treatment is prohibited and would be subject to enforcement action by the FERC.

VI. SCOPE CHANGES

Schedule 12C, Section 2 of the Section II of the ISO Tariff provides:

> If the costs associated with a Transmission Upgrade exceed the estimated Pool-Supported PTF costs determined in the original Localized Cost review by ten percent, or the design associated with the construction of a Transmission Upgrade is materially changed subsequent to the ISO's determination of Localized Costs, then the applicant for Pool-Supported PTF costs shall be required to submit its Transmission Upgrade again to a review by ISO to determine if any of the incremental costs or costs associated with the change in design are Localized Costs.

The State of Maine has not completed its siting process with regard to this Project. As with other projects that have not yet completed their siting process, the ISO is concerned that the Project may present other areas of Localized Costs once the siting process is complete and the final design determined. Requirements or conditions that the State of Maine may impose on the Project may adversely impact the Project's current cost estimate or may materially change the design of the Project. Therefore, the ISO requests that CMP provide periodic updates on those siting proceedings no less than three times per year, as prescribed in the draft Appendix D to Planning Procedure No. 4, to both the Reliability Committee and the ISO, and a presentation on the final design of the

[62] *See* response ISO-02_(CMP-09-TCA-01) from CMP dated March 12, 2009.

[63] *Id.* CMP further explained the "Contingency and Escalation" categories and noted that those exclude "costs associated with extreme schedule delays resulting from delays in regulatory approval, a disjoint in commodity or labor pricing inconsistent with historical extremes, changes in scope, relocation of portions of the Program and extreme environmental or regulatory conditions." *Id.*

Project. If, after siting is complete, there is a ten percent cost increase or material design change as described in Section 2 of Schedule 12C, an amended TCA application will be required for this Project, and the ISO will conduct another review of the revised project for Localized Costs. Further, the Project must continue to address the regional reliability needs identified through the New England planning process in order to qualify for regional cost treatment as a Regional Benefit Upgrade under the ISO Tariff.

As explained in Section II above, an ISO finding that certain proposed expenses do not constitute Localized Costs should in no way be interpreted as a determination by the ISO that such estimates are accurate and should automatically be included in the regional transmission revenue requirement collected by the PTOs through Attachment F of Section II of the ISO Tariff. The regional revenue requirement is based on actual costs (either already incurred or forecasted but trued-up, with interest).

VII. CONCLUSION

In summary, the ISO finds that $1,375,904,000 of the $1,375,904,000 requested by CMP are properly categorized as Pool-Supported PTF Costs. The reasons identified for this determination are consistent with the criteria set forth in Schedule 12C of the ISO Open Access Transmission Tariff for receiving regional support and inclusion in Pool-Supported PTF rates.

Sincerely,

Stephen J. Rourke
Vice President, System Planning

cc: TCApps
Reliability Committee

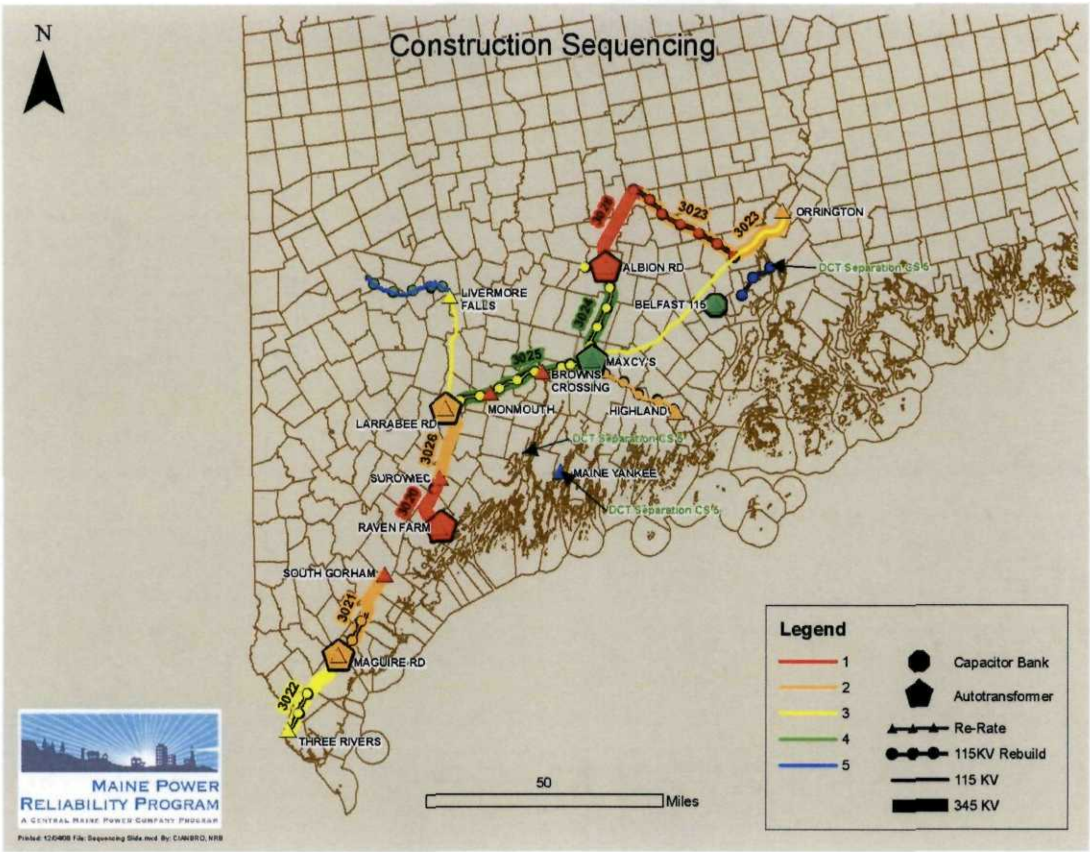

Figure 7 – MPRP Construction Sequencing

Figure 8 summarizes the target start of construction and completion dates for each of the sequences described below.

Sequence	Target start of construction	Target completion
I	July, 2009	May, 2011
II	March, 2010	January, 2012
III	August, 2010	November, 2011
IV	July, 2011	January, 2012
V	February, 2012	July, 2012

Figure 8 – MPRP Construction Target Dates

Sequence I consists of the following major portions of the MPRP scope:

1. Raven Farm to Surowiec 345 kV Transmission Line
    a. Rebuild 115 kV Sections 166 and 167 to allow 345 kV line addition
    b. Second 345/115 kV autotransformer at South Gorham
    c. Surowiec Substation expansion
    d. New Raven Farm Substation with 345/115 kV autotransformer
2. Albion Road to Detroit 345 kV Transmission Line
    a. Rebuild 115 kV Sections 66 and 67 to allow 345 kV line addition
    b. New Albion Road Substation with 345/115 kV autotransformer
3. Other MPRP Scope
    a. Rebuild 115 kV Section 203 to allow 345 kV line addition
    b. New Monmouth Substation with tie in to 115 kV Section 212
    c. Relocate existing Browns Crossing as a 34.5 kV Substation to allow 345 kV line addition (to be built outside of MPRP)
    d. Re-Rate the following Sections: 167A, 61A, 67A, 83B, and 83C

Sequence II consists of the following major portions of the MPRP scope:

1. Maguire Road to South Gorham 345 kV Transmission Line
    a. Rebuild 115 kV Section 238 to allow 345 kV line addition
    b. Maguire Road Substation expansion with 345/115 kV autotransformer
2. Surowiec to Larrabee Road 345 kV Transmission Line
    a. New Larrabee Road Substation with 345/115 kV autotransformer
3. Detroit to Orrington 345 kV Transmission Line
    a. Orrington Substation expansion
4. Coopers Mills[5] to Highland 115 kV Transmission Line
    a. Rebuild 115 kV Section 80 to allow 115 kV line addition
    b. Highland Substation Expansion

[5] In the course of refining the design and scope of the project, MPRP determined that Maxcys substation should be replaced by a new substation at essentially the same location. The new substation has been designated Coopers Mills.

5. Other MPRP Scope

    a. Remove 34.5 kV Section 41

Sequence III consists of the following major portions of the MPRP scope:

1. Three Rivers to Maguire Road 345 kV Transmission Line

    a. Rebuild 115 kV Section 250 to allow 345 kV line addition

    b. New Three Rivers Switchyard (coordinated with NU)

2. Coopers Mills to Orrington 115 kV Transmission Line

3. Larrabee Road to Livermore Falls 115 kV Transmission Line

    a. Expansion of Livermore Falls 115 kV Substation

4. Coopers Mills to Highland 115 kV transmission line

5. Other MPRP Scope

    a. Rebuild 115 kV Section 258 (Formerly 84) to allow 345 kV line addition

    b. Rebuild 115 kV Section 84 for reliability

    c. Rebuild 115 kV Section 60 to allow 345 kV line addition

    d. Rebuild 115 kV Section 88 to allow 345 kV line addition

    e. Rebuild 115 kV Section 212 to allow 345 kV line addition

Sequence IV consists of the following major portions of the MPRP scope:

1. Albion Road to Coopers Mills 345 kV Transmission Line

    a. Coopers Mills Substation

2. Larrabee Road to Coopers Mills 345 kV Transmission Line

3. Other MPRP Scope

    a. Rebuild 115 kV Section 89 to allow 115 kV line addition

    b. Rebuild 115 kV Section 229 to allow 115 kV line addition

Sequence V consists of the following major portions of the MPRP scope:

1. Livermore Falls to Rumford IP 115 kV Transmission Line

2. MPRP Double Circuit Tower Separations
    a. Separate 345 kV DCT at the Kennebec River Crossing
    b. Separate 345 kV DCT at Maine Yankee
    c. Separate 115 kV DCT at Bucksport
3. Other MPRP Scope
    a. Rebuild 115 kV Section 86 for reliability
    b. Maine Yankee Substation Expansion
    c. Belfast Substation expansion and Capacitor Bank addition