CENTRAL MAINE POWER

November 8, 2012

Karen Geraghty
Administrative Director
Maine Public Utilities Commission
State House Station #18
Augusta, ME 04333-0018

Re: MAINE PUBLIC UTILITIES COMMISSION, Investigation into Maine‟ s Electric Utilities Transmission Planning Standards and Criteria, Docket No. 2011-494

Dear Ms Geraghty:

Enclosed for filing in the above-captioned proceeding is Central Maine Power Company's Post – Hearing Brief.

Respectfully submitted,

Debra J. Mills

Debra J. Mills
Lead Analyst, Regulatory Administration

Enclosure

83 Edison Drive, Augusta, Maine 04336
Telephone 207-623-3521
www.cmpco.com

IBERDROLA USA

Printed on recycled paper

STATE OF MAINE
PUBLIC UTILITIES COMMISSION

Docket No. 2011-494

November 8, 2012

CENTRAL MAINE POWER COMPANY)
)
Investigation into Maine's Electric)
Utilities Transmission Planning)
Standards and Criteria)

POST HEARING BRIEF OF CENTRAL MAINE POWER COMPANY

Central Maine Power Company (CMP) submits the following as its post-hearing brief.

I. INTRODUCTION

Much common ground has been confirmed so far in this investigation. The Staff and CMP agree that the general purpose of transmission planning, whether of the "Bulk Electric System" (BES) or the lower voltage "local" or subtransmission system is to assess, plan and design a transmission system that can remain reliable over the planning horizon across a wide spectrum of possible future scenarios. (9/17/12 Tr. at 13:13 – 14:18; CMP Rebuttal at 3.) The Staff and CMP also agree that transmission planning engineers conduct this planning by conducting load flow modeling studies of "reasonably stressed" base cases, which reflect assumptions for the expected load and generation dispatch during the planning horizon, and the planning engineers are concerned not only with planning a transmission system for the system peak conditions for the study year, when all generation and transmission facilities are expected to be in service. (9/17/12 Tr. 13:13 – 14:18 & 25:19 -27:14; CMP Rebuttal at 3-4.) As discussed in Section II below, the Staff and CMP also agree on many of the assumptions used in establishing the reasonably stressed base cases and the testing methodologies used in the load flow modeling.

There remain a handful of areas of dispute, where the Staff believes that CMP overstresses the system as part of planning its local transmission system. CMP disputes the

Staff's view of each of these points for the reasons set forth in its January 17, 2012 Preliminary Report, July 13, 2012 Comments, and October 3, 2012 Rebuttal and as explained by its witnesses during the October 26, 2012 hearing. Section III below sets forth CMP's position with respect to each of these points and why, contrary to Staff's claims, CMP's use of these assumptions and practices reflect sound engineering judgment and good utility practice which should be expressly acknowledged by the Commission.

The criteria CMP uses in setting the generation dispatch reasonably stress the system. CMP's consistent use of PP-7 ratings for all of its transmission facilities is appropriate, particularly given the high temperatures that southern Maine experiences from time to time. The reduced load level CMP uses for planned maintenance testing is justified by actual peak loads experienced on CMP's system over the last five years. And, CMP's application of the applicable NERC, NPCC and ISO-NE planning criteria to any BES/PTF transmission components within a local planning study and mitigation of any violations identified in such testing reflects good utility practice, facilitates CMP's compliance with all mandatory federal transmission planning standards, and helps ensure that CMP's transmission system will remain reliable now and in the future across a wide spectrum of possible future scenarios.

Section IV below then sets forth CMP's view on the limitations of the Commission's jurisdiction to dictate the standards CMP must use to plan its transmission system and addresses the particular questions posed during the hearing by Chairman Welch related to preemption. In short, under federal law, FERC has exclusive authority over the regulation of the planning and operation of transmission facilities used in interstate commerce, which includes CMP's lower voltage sub-transmission facilities. The planning of CMP's local sub-transmission system is governed by Attachment K – Local of ISO-NE's FERC approved tariff, under the terms of which

FERC has designated CMP as the party responsible for determining the need for any transmission upgrades on that system to maintain reliability. The Commission retains authority under Maine law to determine the appropriate solution to address the identified needs and to approve the siting of the transmission upgrades. However, federal law preempts the Commission from mandating the applicable planning criteria even for non-BES transmission facilities.

In any case, for the reasons discussed in Section III, CMP believes that a preemption challenge should not be necessary because the Company's planning criteria for its local transmission facilities, as set forth in the Iberdrola Electric System Planning Manual – Criteria & Processes (Exhibit A to CMP's Preliminary Report), are reasonable and appropriate given the configuration of CMP's transmission system and should be found to be so by the Commission. By making this finding, the Commission will achieve its "hope and expectation" that after this investigation the "ad hoc examination" of the appropriate planning standards in every future transmission certificate proceeding will be avoided.

II. POINTS OF AGREEMENT

As Staff acknowledged, the transmission planning flowchart CMP presented as Exhibit CMP-02 accurately reflects the process CMP intends to use to plan its transmission system once FERC adopts NERC's bright-line definition of the BES. (Tr. at 126:3-18.) As such, it provides a useful scorecard to track the several areas in which there is no disagreement between the Staff and CMP over the appropriate criteria for CMP to use to plan the lower voltage components of its transmission system. The areas of agreement are as follows:

Base Case

- **Load**

It is appropriate for CMP to use a 90/10 peak load forecast for purposes of setting a reasonably stressed base case for planning its BES/PTF and local transmission systems. (10/26/12 Tr. at 126:24 – 127:3.)

- **Interface Limits**

It is appropriate for CMP to set the transfer limits according to the applicable NERC, NPCC and/or ISO-NE standard in any study of BES/PTF elements of CMP's transmission system. (9/17/12 Tr. at 78:18 – 79:14.) Testing the effect on the local transmission system of bulk transfers set at the established maximum levels permits CMP to determine whether there are any bulk system violations. (Bench Analysis at 21.)

The appropriateness of also setting the transfer limits at their maximum values as part of local area studies is discussed in Section III(B) below.

- **Ratings**

It is appropriate for CMP to use its existing PP-7 ratings (using the ISO-NE established reference temperatures) for all of its BES/PTF transmission facilities and its new local transmission facilities. (10/26/12 Tr. at 127:14 – 19; Bench Analysis at 21.)

Testing

- **Non-BES/Local Elements**

It is appropriate for CMP to test all non-BES/local transmission facilities to an N-1 standard for single element contingencies and to employ a 25 MW loss of load criteria as part of this testing. (10/26/12 Tr. at 139:10-18.) As such, any violations from this testing that result in more than 25 MW of consequential load loss must be addressed.

- **Planned Maintenance (Non-BES/Local Elements)**

It is appropriate for CMP to conduct planned maintenance testing on its non-BES/local transmission facilities. This testing will be conducted at a reduced load level, assume one transmission element out of service, consist of N-1 testing for single element contingencies, employ a 60 MW loss of load criteria, and use mobile transformers as appropriate. And, any violations from this testing that result in more than 60 MW of consequential load loss must be addressed. (10/26/12 Tr. 139:10 - 141:20.) Thus, as discussed in Section III(D) below, the only point remaining in dispute is the proper reduced load level for this testing.

- **BES/PTF Elements**

It is appropriate for CMP to test the BES/PTF transmission elements on its system using the applicable NERC, NPCC and ISO-NE planning standards and criteria (*i.e.*, N-1-1 testing and the application of NERC/NPCC contingencies including Category C multiple element contingencies) and the ISO-NE Planning Manual, whether as part of a local area study or a broader comprehensive study of the transmission system within CMP's service territory. It is also appropriate for CMP to address any violations identified through this testing on: (i) BES/PTF transmission elements; and/or (ii) non-BES transmission elements to the extent such violations impact the BES/PTF transmission system. (10/26/12 Tr. at 150:9 -152:11; CMP Rebuttal at 10; CMP 07/13/12 comments at 10-11.)

The reasons why CMP should also address any violations identified through this testing on its lower voltage transmission facilities on its system that do not impact the BES/PTF transmission system are discussed in Section III(E) below.

* * * * * * *

CMP respectfully requests that the Commission incorporate each of these points of agreement in its final order in order to provide the Staff and parties clarity on these points to avoid any disagreements over them in future CPCN proceedings. [1]

III. REMAINING POINTS OF DISAGREEMENT

As discussed during the hearing, there remain a handful of points where Staff disagrees with the planning assumptions and practices that CMP's transmission planning engineers use for identifying the reliability needs of the local transmission facilities within CMP's service territory. Staff claims that CMP is unreasonably stressing the local transmission system and therefore identifying too many violations and in turn too many needed transmission upgrades. In particular, Staff disputes the following:

- CMP's use of a "two-generator out" assumption in local planning area studies;
- CMP's setting of the transfer limits for interfaces within the load flow model at their maximum values when conducting local planning area studies;
- CMP's use since 2009 of the PP-7 ratings (with ISO-NE ambient temperatures) for all of its existing local transmission facilities;
- CMP's use of a 85% of 90/10 peak load forecast for planned maintenance testing; and
- CMP's position that all violations identified on local transmission facilities, whether or not they impact the BES system, arising from testing BES/PTF elements according to NERC, NPCC and ISO-NE planning standards and criteria, (*i.e.*, N-1-1 testing and the application of NERC/NPCC contingencies including Category C multiple element contingencies) must be addressed.

CMP responds to each of these points below.

[1] CMP's rebuttal lists a few other points where the Staff in the Bench Analysis agreed with the utilities; these points should also be adopted in the Commission's final order. (CMP Rebuttal at 7.)

As a starting point, it is important to recognize that to date Staff has offered no engineering basis (and in some cases no analysis whatsoever) for its positions with respect to these points, and no other party to this investigation has offered any engineering support for Staff's positions. Instead, without the benefit of any input from a transmission planning engineer on staff or under contract as a consultant, Staff has simply indicated their view that CMP's assumption and practices (which have been developed over many years by CMP's in-house and outside planning engineers most familiar with CMP's transmission system) are too stringent in these respects and will result in too many transmission upgrades in the future. Staff has also failed to present any methodology or metric for the Commission to use to decide what constitutes "reasonable" as opposed to "unreasonable" stress in planning studies.

During the hearing, Staff attempted to downplay these shortcomings in their analysis by suggesting that with respect to each of these points CMP has changed its approach from the past and the Company has not presented a sufficient cost/benefit analysis supporting this change. As such, the Commission should simply decide that CMP has not met its burden in this investigation to demonstrate the reasonableness of its approach.

In response, CMP must make clear that several of the points above do not reflect any change in CMP's planning practices. So, for example, CMP has consistently developed its base case generation dispatch by considering what amount of generation will "reasonably stress" the transmission system under study. In doing so, CMP has long considered whether multiple thermal generators should be modeled as off-line in a local planning area study based on the particular configuration of the system under study and the characteristics of the generation involved, and where appropriate CMP has assumed multiple generators off-line. The 2001 Portland local area study demonstrates this point clearly. In that study, in order to appropriately stress the local transmission facilities in the Portland area for testing purposes, CMP modeled the W.F. Wyman and Cape units as all on-line to test one stressed system condition and all off-line to test another stressed system condition. (EX-04-01 (b).) Likewise, for many years, CMP's load flow model used for local area studies has set the New Brunswick-Maine transmission interface transfer at its limit, and its planning criteria have since 1993 called for planned maintenance testing to be conducted at 85% of the tested load level. (10/18/12 Tr at 42:9 - 20.)

In any case, Staff's approach will require the Commission to decide what constitutes "reasonable stress" for local planning studies in Maine generally and with respect to CMP's transmission system in particular.[2] Deciding that CMP has failed to present a sufficient quantification of the benefits of any particular change in its planning standard is necessarily a determination that Staff's alternative approach represents good planning practice and will provide the appropriate level of reliability for CMP's transmission system.

For the following reasons, CMP respectfully asserts that Staff's positions with respect to each of the remaining points in dispute do not represent good planning practice and should not be adopted by the Commission. The Commission should instead acknowledge that CMP's standards are reasonable and appropriate given the configuration of its transmission system, the characteristics and historical performance of the generation within its service territory, and the historical weather conditions and demand experienced therein.

A. Generator Dispatch

Distilled down, the Staff's issue with respect to generation dispatch is that CMP should not automatically and in every case apply a two-generator out assumption in setting the

[2] For the reasons discussed in Section IV, the Commission's determination may not be legally binding under federal law, but nonetheless will reflect what it believes appropriate under good utility practice for CMP to use in planning its sub-transmission system.

generation dispatch in its base case for local area studies. The record, however, reflects that CMP does not simply rigidly apply such an assumption in setting its generation dispatch for all local area studies.[3] Rather, CMP's transmission planning engineers assess the generation in the area under study to determine what dispatch of that generation will provide reasonable stress during the load flow modeling. Given the configuration of its sub-transmission system, which is networked to a far greater degree that BHE's, and the interrelationship between the generation and load within its service territory, in CMP's judgment in many, but not all cases, "a two-generator out dispatch assumption based on generator type, interconnection with the system, historical availability, and size is appropriate to adequately stress the system for planning purposes." (CMP Rebuttal at 20-21.) So, for example, in the Saco and Portland areas, the prevalence of multiple critical generators which can and do serve load but which can place different stresses on the transmission system under certain conditions justified the use of two-generator out dispatch assumptions. (06/15/12 Tr. at 124 - 25; CMP 07/13/12 Comments at 6, 10/18/12 Tr. at 22.) In contrast, other areas of CMP's system lack thermal generation and in those instances CMP historically has not assumed two (or even any) generators completely off-line in local planning studies. (EX-04-01(b).)

CMP's transmission planning engineers, thus, use a two-generator out dispatch where it is appropriate in their engineering judgment to reasonably stress the system under the circumstances. Staff, in fact, concedes that it is reasonable and appropriate in certain areas of CMP's transmission system to use a two-generator out assumption for planning purposes based

[3] As explained in CMP's Preliminary Report (at 4-7), regional planning studies of the BES/PTF system within CMP's service territory are conducted by ISO-NE and ISO-NE's planning criteria mandate the use of a two-generator out generator dispatch. (Ex.CMP-04 at 25.)

on the expected load, the historical and expected future performance of generation, and configuration of the transmission system in the area under study.[4] (10/26/12 Tr. at 136:15 – 21.)

The question is thus under what circumstances is the use of a two-generator out dispatch assumption appropriate. The simple answer is that such a dispatch case should be used whenever it will "reasonably stress" the system for planning purposes. CMP's approach to setting a base case that reasonably stresses the system is to consider the generators located within the area under study by type, historical performance and expected future performance. (ODR-04-02 & 07/13/12 Comments at 6.) Run-of-the-river hydro is typically dispatched according to a low-hydro condition output representing a value that occurs at or less than 15% of the time according to the facility's flow duration curve, although in some circumstances a different dispatch may be used to reasonably stress the system. (*Id.*) Other types of generation including wind, other hydro, bio-mass and thermal are modeled at full output and/or as off-line based on the planning engineer's judgment as to what dispatch will most stress the transmission system. (*Id.*)

For local areas where multiple thermal or bio-mass generators have the largest impact on the area under study, CMP's starting assumption is to dispatch two of these units offline at the same time. CMP uses this starting point assumption in order to ensure that its sub-transmission system in a given area is able to continue to serve load reliably even with the local generation not operating. This approach avoids a delivery system whose reliability is entirely dependent on a specific generation dispatch, and therefore furthers the policy goal of avoiding a transmission system designed to make the continued operation of any generator necessary, such that an

[4] Staff has suggested that cases with multiple generators not operating should be considered "sensitivities." CMP does not object to running multiple dispatch cases and, in fact, often does so when the tested cases are expected to stress the transmission system in different ways. So, for example, the 2001 Portland local area study tested cases with the W.F. Wyman and Cape unit on and off-line and the MPRP planning studies tested several different generator dispatch base cases. CMP believes however that any violations identified through any case the planning engineers determine appropriate to test must be addressed and not simply be considered for "informational purposes."

Reliability Must Run (RMR) agreement and/or non-economic dispatch is required to ensure transmission reliability.[5] (CMP Preliminary Report at 11; CMP Rebuttal at 21.) CMP's planning engineers validate the appropriateness of this assumption by reviewing historic operational data reflecting the actual output of the generators during various times of the year under study, instances where the generator failed to operate due to fuel shortages or other reasons, the historical performance of the generators, and any information about anticipated changes in future operation, such as known or expected retirements or delists. (ODR-04-02 & 07/13/12 Comments at 6.)

Staff has acknowledged that in setting the generator dispatch that reasonably stresses the system for a planning study it is appropriate for the planning engineer to consider these factors. (10/26/12 Tr. at 137:7 – 138:13.). Staff, however, continues to assert that assuming two generators out in a local area will in their judgment unreasonably stress the system. Staff's recommended generation dispatch would instead be based on a generator's historical availability during peak conditions, subject only to information about the known future retirement or delist of that generator. Thus, in Staff's view, if a generator was available to operate during prior peak periods it should be modeled as on-line in the base case (presumably at full output or at least at some average historical output) used to determine the transmission needs ten years in the future.[6]

[5] Achieving this policy goal can provide significant cost savings to customers.As evidenced by New York's recent experience with RMR contracts needed for transmission reliability purposes costing upwards of $100 million per year, (10/26/12 Tr. at 40:3-18.)

[6] In the Bench Analysis and during the September 17 and October 18 technical conferences, the Staff pointed to the historical forced outage rates of thermal generators as being an important data point in setting an appropriate generation dispatch. CMP does not understand how one would use a forced outage rate to set the generation dispatch for planning purposes and Staff was unable to provide any guidance. (CMP Rebuttal at 19; 09/17/12 Tr. at 89 - 90.) So, for example, if a generator has a 10% forced outage rate, the planning engineer knows that the unit will not be available 10% of the time. However, should the planning engineer assume that the generator will be off-line or operating at 100% output for purposes of the generation dispatch base case? The forced outage rate provides very little guidance to this question.

Such a generation dispatch, however, would not constitute good planning practice. It would not reasonably stress the system for planning purposes and ignores the purpose of transmission planning, the economic realities of the New England generation market, and the operating limitations of many of the thermal generation units in CMP's service territory. An appropriately planned transmission system must be able to reliably provide service across a wide spectrum of conditions throughout the entire year. Assuming all thermal generation on-line at some historical average level will not ensure such a transmission system. This is particularly true since at least in CMP's service territory it is a common occurrence for certain thermal generators to be off-line for economic reasons even during hot periods in the summer. (CMP Preliminary Report at 11, note 10; EX-01-04 (d.).) In fact, CMP has presented data that in certain areas on its system, including most notably the Portland and western Maine areas, multiple thermal generators have historically been off-line at the same time even during hot summer conditions. (CMP Rebuttal at 21; CMP Preliminary Report at 11 - 12.) The actual occurrence of these conditions demonstrates the appropriateness of using them to establish a reasonably stressed based case: CMP does not have to imagine that these conditions reasonably might occur to stress the transmission system; CMP knows that they have occurred in the past and are likely to occur again in the future.[7] While Staff offers no definition of what constitutes "reasonable stress," they have conceded that a reasonably stressed condition is one that has a reasonable likelihood of occurring, (9/17/12 Tr. at 14:7 -15:9), and these conditions have in fact occurred repeatedly.

---

[7] During the hearing, Chairman Welch asked how Staff would use the facts of a similar scenario to set an appropriate generation dispatch base case. While acknowledging that a two-generator out dispatch was a possibility, Staff again pointed to historical availability as the answer. (10/26/12 Tr. at 120:16 -121:15.) Of course, testing the transmission system with all generators operating at their historical availability will tell the planning engineer nothing about how the system will operate during the times when those generators are not running, as will actually occur even during hot days in the summer.

In addition, the Commission should not ignore the operating limitations of certain of the thermal units in CMP's service territory as the Staff continues to do. The fundamental premise of Staff's approach to generation dispatch is that all (or at least most) of the thermal generation in CMP's service territory will be on-line during peak conditions and/or able to respond in the event of a transmission contingency and therefore should be assumed on in all planning studies. The evidence shows, however, that some of the key thermal units, such as the W.F. Wyman units, are not economically dispatched even during hot conditions in the summer. (CMP Rebuttal at 22.) The evidence also shows that these units have very long start-up times such that they simply cannot be started to respond in time to a transmission contingency. That these units are "available" and have a capacity obligation with the Forward Capacity Market does not change either of these realities. As such, the only way that these units can be relied upon for transmission reliability is to make sure they are running pre-contingency. This then will lead to significant RMR and/or non-economic dispatch costs, which costs will have to be borne entirely by Maine customers. Assuming such generation as being on-line in planning studies, modeled at historical availability, only increases the likelihood that such costs will be necessary.

In sum, CMP believes that the approach that its transmission planning engineers use to setting the generation dispatch in planning studies reflects good utility practice and reasonably stresses the system for planning purposes. CMP recognizes that the determination of the appropriate generation dispatch that will provide reasonable stress in a particular area must be done on a case by case basis, such that consideration of that dispatch may be necessary in future CPCN proceedings. Nonetheless, CMP believes that the record supports the Commission making the following findings, which will go a long way to minimizing disputes over the generation dispatch in those future proceedings:

- The generation dispatch should be set according to the following parameters, where applicable:
  - Run of the river hydro generation should be dispatched at a low hydroelectric generation level based on the historic flow duration curve for the facility in the event it is a stressed system condition;
  - Variable generation such as wind and solar should be dispatched at either off-line or at maximum output depending on whether either is a stressed system condition;
  - Two stand-alone thermal generating units or a combination of a stand-alone unit and a combined-cycle generating plant should be modeled as off-line for those areas where such generation facilities have the largest impact on the area under study; and
  - If a full generation dispatch in an area is a stressed system condition, it should be tested as well.
- In setting the generation dispatch, the utilities should review the historic operational data reflecting the actual output of the generators during various times of the year under study, instances where the generator failed to operate due to fuel shortages or other reasons, the historical performance of the generators, and any information about anticipated changes in future operation, such as known or expected retirements or delists.

B. Interface Limits

The subject of CMP setting the interface transfer limits at maximum values in its load flow models was discussed very little during the hearing and for good reason. While in the Bench Analysis the Staff questioned CMP's practice of honoring the bulk area transfer limits when performing local area studies, the Staff's concerns are misguided for the reasons discussed on pages 25-26 of CMP's Rebuttal. There should be no dispute on the following points, which demonstrate why CMP's practice is not only good utility practice, but should be required:

- Interface transfer limits are important to the efficient and economic operation of regional grid and must be honored when operating the transmission system;
- At least portions of CMP's sub-transmission system operate as parallel paths for the BES system and therefore can potentially impact the BES and interface transfer limits; and

- CMP cannot make changes on its sub-transmission system that impact the interface transfer limits and, in fact, any changes to facilities within ISO-NE which require a Proposed Plan Application (“PPA”) and supporting study, must show that the proposed changes will not adversely impact either interregional or intraregional transfer limits.

It is important to recognize that in some local area studies within CMP’s service territory the bulk interface transfer limits have little to no impact on the results, particularly where CMP’s sub-transmission system consists of radial 34.5 kV lines. (10/18/12 Technical Conference Tr. at 57:7 - 12.) In other areas where CMP’s sub-transmission system is networked to a greater degree, the interface transfer limits, however, do provide meaningful stress on the lower voltage system because those portions of the system act as parallel paths for flows. Stressing interfaces to the “maximum” in transmission studies for such areas is important as it helps ensure that the existing capability of the transmission system is not diminished.

C. Ratings

After much back and forth over the last several years, the dispute over what ratings CMP should use for its transmission facilities for operational and planning purposes is now quite narrow. As discussed in Part II above, the Staff agrees that it is appropriate for CMP to use its existing PP-7 ratings (using the ISO-NE established reference temperatures) for all of its BES/PTF transmission facilities and its new local transmission facilities. The Staff also does not object to CMP using the PP-7 rating methodologies for existing sub-transmission facilities, provided the ratings calculation for those facilities uses CMP specific reference ambient temperatures. (10/26/12 Tr. at 127:24 – 128:10.)

Staff disagrees with CMP's application of PP-7 to existing transmission lines and equipment, because doing so may drive the need for upgrades. Bench analysis at 21. In particular, Staff has expressed concern that the ambient temperatures used in the PP-7 standards are too high. (*Id* at 22 - 23.) Thus, the remaining question is: what are the appropriate ambient temperatures for rating existing sub-transmission facilities in CMP's service territory? For the reasons discussed in CMP's Rebuttal (at pages 26-31) and by its witnesses during the hearing, CMP submits that the ISO-NE derived ambient temperatures are appropriate for all of its transmission facilities and that the Commission should not call for CMP to re-rate all of its existing sub-transmission facilities based on different ambient temperatures.

As reflected in Appendix A to ISO-NE Planning Procedure No. 7, Procedures for Determining and Implementing Transmission Facilities in New England, ISO-NE directs that 100 °F (38 °C) be used for determining the normal and emergency summer ratings for overhead conductors and 77 °F (25 °C) and 89.6 °F (32 °C) respectively be used for determining the normal and emergency summer ratings for transformers. The conductor summer ambient reference temperature is drawn from Section 125.23 of Chapter 220 of the Code of Massachusetts Regulations, Installation and Maintenance of Transmission Lines (220 CMR 125.23). (ISO New England Planning Procedure No. 7, Appendix A, § 2.1.1.) The reference temperatures for transformer emergency ratings were determined, consistent with IEEE Standard C57.91-1995, by calculating a weighted average of the "average of maximum daily temperatures" for Hartford, Connecticut, for the appropriate months and then adding 5 °C. (ISO New England Planning Procedure No. 7, Appendix A, § 2.1.2.) In the case of summer ratings, summer temperatures were determined by equal weighting of the temperatures for the months of June through September. (*Id.*)

In Attachment 2 to ISO-NE Planning Procedure No. 7, ISO-NE also provided its assessment of the appropriateness of using Hartford temperatures as a reference for all of ISO-NE's service territory by comparing the Hartford average temperatures used to calculate the transformer ratings with the average temperatures for eight other New England cities including Portland, Maine. This comparison showed that the reference temperatures ISO-NE uses for transformer ratings were appropriate for all of New England, although they did exceed Portland's average temperatures by 1-4 °C.

As discussed in detail in CMP's Rebuttal, this modest difference should not lead the Commission to order CMP to reduce the ambient temperature it uses to rate its existing non-PTF transmission facilities. The adjustment of the PP-7 ratings for CMP's non-PTF transmission facilities to reflect historical average peak temperatures for Portland or southern Maine will have very little impact on the ratings for those facilities, but will impose the cost and burden of changing the ratings and maintaining them for all existing (as opposed to new) facilities. Such an adjustment will have no effect on the line ratings that are limited by a component that is not temperature driven (such as switches). (CMP Rebuttal at 27 & 29.)

With respect to transformer ratings, CMP's Rebuttal demonstrates that adopting a Portland or southern Maine derived ambient temperature will only change the ratings multiplier from 1.20 to 1.22 or 1.23, which as shown in Table 2 from CMP's Rebuttal reproduced below, results in a minimal impact on the summer long term emergency rating of a typical 50 MVA 115/34.5 kV transformer.

Table 2
Summer Long Term Emergency Rating for a
Typical 50 MVA 115/34.5 kV Transformer

Ambient Temperature	Overload Multiplier	Summer LTE Rating
32 °C	1.20	60.0 MVA
29 °C	1.22	61.0 MVA
28 °C	1.23	61.5 MVA

CMP believes that this small difference would seldom impact the recommended solutions to identified reliability problems. (CMP Rebuttal at 30.) Given this modest impact, CMP urges the Commission to refrain from calling for CMP to expend the significant time and resources necessary to re-rate all of its non-PTF transformers based on a southern Maine derived reference temperature.[8]

Likewise, with respect to overhead conductors, CMP believes strongly that the use of 100 °F (38 °C) is appropriate for its service territory and should not be changed simply because the historical average temperatures in Portland are modestly lower than those in Hartford, as Staff seems to suggest. It is important to understand, as discussed above, that the average temperatures set forth in Attachment 2 to ISO-NE Planning Procedure No. 7 do not drive the use of 100 °F for rating overhead conductors in New England. Rather, ISO-NE's use of this temperature is derived from the applicable Massachusetts regulation.[9]

This distinction is critical because of the important differences in rating overhead conductors as opposed to transformers. Transformer ratings are calculated to allow a certain loss of life to the unit based on elevated temperatures. It is not a clearance or safety issue. A transformer also has a relatively high thermal mass, so its temperature will not change rapidly based on changes in the ambient temperature. (10/26/12 Tr. at 52:16-25.) In contrast, overhead conductors have much lower thermal mass than transformers and hence their temperature can change rapidly, within an hour, because of a change in ambient temperature. (*Id.*) More

[8] Should the Commission nonetheless call for CMP to adopt reference temperatures specific to its service territory, CMP urges the Commission to reject Staff's recommendation that Portland temperatures be used. Given its location adjacent to Casco Bay, Portland's temperatures are milder in both winter and summer than more inland cities within CMP's service territory such as Sanford or Lewiston. A system wide reference temperature should reflect the actually experienced high and low temperatures.

[9] It is worth noting that the data in Attachment 2, Table 8, upon which Staff relies shows that the historical average temperatures in Worcester, Massachusetts are comparable to those of Portland, but nonetheless Massachusetts has mandated the use of 100 °F (38 °C) for rating overhead conductors.

importantly, for a transmission line that is sag limited, clearance standards to ground will be violated and public safety will be jeopardized at temperatures above that assumed in calculating the ratings. Thus, if ratings were calculated based on 95 °F, but actual ambient temperatures higher than that are experienced, the line will exceed its sag limit in violation of National Electric Safety Code. In that instance, however, the system operator will not be required to take action unless the load levels on the line exceed the rating calculated at 95 °F. Thus, for rating overhead conductors it is important to use actual experienced peak temperatures as opposed to some sort of average of peak temperatures because by definition the actual peaks will exceed the average some of the time in the future. In short, good utility practice calls for the rating and sag calculations to reflect reasonably expected maximum ambient temperatures.

As shown in response to EX-04-08, and based on empirical evidence, temperatures in CMP's service territory have exceeded 100 °F and routinely are in the upper 90s °F. (10/26/12 Tr. at 53:1 – 54:25.) Given this temperature data and the physical differences between overhead conductors and transformers discussed above, CMP urges the Commission to refrain from calling for CMP to expend the significant time and resources necessary to re-rate all of its non-PTF overhead conductors based on a southern Maine derived average reference temperature. The use of 100 °F for rating all overhead conductors in CMP's service territory makes sense given historical experience and will ensure that all of CMP's ratings are calculated consistently for planning and operations purposes in accordance with New England's recognized "best ratings practices" as they have been since 2009. Maintaining these ratings at their current level will make the operation and design of CMP's entire transmission system simpler and less prone to error. (CMP Rebuttal at 28.) Doing so will not necessarily cost CMP's customers more, as lowering the ambient temperature will have no effect on the line ratings that are limited by a component that is not temperature driven, (*id.* at 29), but may reduce the normal ratings on many lines, which could increase the likelihood of congestion in the day ahead and real time electricity markets during some system conditions to the detriment of customers. (*Id*. at 28.)

D. Planned Maintenance Testing Reduced Load Level

The only issue remaining in dispute with respect to planned maintenance testing is the appropriate reduced load level for that testing. CMP uses 85% of its 90/10 peak load forecast for this purpose. The Staff believes that this is an "overly stressed case" and instead continues to recommend that planned maintenance testing be performed at 75% or 85% of CMP's 50/50 peak load forecast notwithstanding the data CMP presented in Table 1 and Exhibit 1 to its Rebuttal which shows that over the last five years the actual monthly peaks on CMP's system regularly exceeded these levels even during the shoulder months when planned maintenance is performed. CMP respectfully submits that conducting planned maintenance testing (and mitigating any violations found as result) at either of these load levels will not fulfill the purpose of planned maintenance testing, namely to design the sub-transmission system to remain reliable during an appropriate window of time when facilities are removed from service for planned maintenance.

There appears to be no dispute that the load level selected for planned maintenance testing is intended to establish a reasonable amount of "head room" between the load level for which the system is designed and the expected monthly peaks during the window in which planned maintenance will be permitted. The data presented in Table 1 and Exhibit 1 to CMP's Rebuttal, which compares the actual monthly peaks experienced on CMP's system during the years 2007 -11 against the then most current CMP peak load forecast adjusted to reflect the various reduced load levels under consideration shows clearly that Staff's proposed 75% of 50/50 load level is unreasonably low as it has been exceeded in all but three months over the last five years and therefore provides no head room for planned maintenance. (CMP Rebuttal at 12.) The results at the 85% of 50/50 level are only modestly better, showing that at best only April and May could be considered for performing planning maintenance with that reference load. (*Id.*) In contrast, the data supports the use of CMP's proposed 85% of 90/10 reference load level, as actual monthly peaks in most (but not all) of the shoulder months have been less than this level during the last five years. (*Id.*) "Designing CMP's transmission system to an 85% of 90/10 load level thus helps ensure that maintenance can be done safely during those months with minimal risk of service interruptions." (*Id.*)

Staff's only response to this evidence appears to be that CMP is using the wrong data for comparison purposes. Instead of using the then most recent peak load forecast (so for example, the 2008 forecast for the 2009 comparison), CMP should have presented its load forecasts from 5-10 years earlier for comparison purposes with actual monthly loads, presumably because such forecasts would have been the ones used by the transmission planners to conduct planned maintenance testing. This approach, however, makes little sense because to make such a review, even if the data still existed[10], would only test the accuracy of CMP's peak load forecasts, not the ability of the power system to accommodate planned maintenance outages. If load forecasting performed years ago had been perfect, then it would have predicted actual loads. The operators deciding whether to schedule planned maintenance outages, however, would not use the ten-year old forecast, but rather the most recent, which reflects CMP's best guess as to expected peak loads during the period in which upcoming maintenance must be planned. That is the data CMP provided with its rebuttal and it showed that actual monthly peak loads regularly exceed the levels Staff propose for planned maintenance testing during the spring and fall shoulder months.

[10] Staff did not request CMP produce this data at any time during this investigation and CMP does not know if it can locate its peak load forecasts going back ten years given its record retention program.

In any case, in order to take the element of forecast uncertainty out of the discussion of what months would work for maintenance planning a review of actual monthly peak loads compared to actual annual peak loads can be performed based on the data in Exhibit 1 of CMP's Rebuttal. The results of that comparison are shown in the table below.

Number of Months in the Five-Year Period 2007-2011 that Actual Monthly Peak Load was Below the Reference Load for the Actual Annual Peak

Load Reference	Below 85% of Annual Peak	Below 75% of Annual Peak
January	0	0
February	1	0
March	2	0
April	5	1
May	4	1
June	2	0
July	0	0
August	0	0
September	2	0
October	3	0
November	2	0
December	1	0

These results show that for the 85% of Annual Peak case there would have been only one or two months, April and possibly May, when a system operator could have felt secure about scheduling planned maintenance had the system been designed to that reduced load level. Results for the 75% of Annual Peak show that there were virtually no months when an operator could have felt secure to schedule such planned maintenance. The actual annual peaks used for these calculations have not been weather adjusted, so they do not necessarily reflect a 50/50 or 90/10 peak; nonetheless they provide further support for the conclusion that planned maintenance testing should be performed at a load level higher than that proposed by Staff. CMP believes that the appropriate load level is 85% of its 90/10 peak, as that load level provides a sufficient level of head room to permit planned maintenance to occur in the spring and fall. It also helps ensure that CMP's transmission system stays reliable throughout the year when maintenance (both planned and emergency) actually takes place.[11]

E. BES Element Testing

The final issue in dispute concerns whether it is appropriate for CMP to address all violations identified through the testing of the BES/PTF elements in its system in accordance with the NERC, NPCC and ISO-NE planning standards including those identified on CMP's sub-transmission system that do not otherwise impact the BES. The appropriateness of CMP assessing its transmission system on a comprehensive basis in the future in order to comply with the reliability standards of NERC, NPCC and ISO-NE and to better understand and plan for the interrelationship between its BES/PTF system and its sub-transmission system in accordance with the recommendations in the Southwest Blackout Report[12] no longer appears in dispute. (10/26/12 Tr. at 150:9 - 20.) Likewise, Staff has correctly acknowledged that CMP must mitigate any violations on the BES system or the sub-transmission system that impact the BES which are identified through testing the BES/PTF components according to the NERC, NPCC and ISO-NE planning standards (*i.e.*, N-1-1 testing using NERC/NPCC/ISO-NE contingencies including Category C multiple element contingencies). (10/26/12 Tr. at 152:6 - 11.)

Much of the hearing focused on why CMP believes it must fix any violations on the lower voltage local system that result from N-1-1 and/or Category C testing of bulk components,

---

[11] During the hearing, Commissioner Littell asked for a count of how many times during the last five years planned maintenance has taken place on CMP's system when the peak load exceeded the 85% of 90/10 peak load level. ODR-04-01 provides this information and shows 67 different planned maintenance projects occurred on days in which the actual peak achieved on the system exceeded the 85% of 90/10 forecast level, and many of these maintenance projects continued over multiple days in which the actual peaks exceeded the 85% of 90/10 level.

[12] Arizona-Southern California Outages on September 8, 2011, Causes and Recommendations California (authored by FERC and NERC) ("Southwest Blackout Report") (Exhibit B to CMP's July 13, 2012 Comments) at pages 82-84 of 153 (Recommendation 9: "TOPs, TPs and PCs should . . . consider the impacts of elements operated at less than 100 kV on BPS reliability.")

including even those that do not impact the BES. The following testimony from David Conroy and Eric Stinneford provides CMP’s response in compelling fashion:

> MR. DES ROSIERS: Now, the $10 million question, we have -- the violation now is on the 34.5 system, but it doesn't on its face impact the bulk system, and we've testified that CMP believes that it must address that. Why do you believe that CMP still must address that scenario, even if it doesn't have an implication, on its face, on the bulk system?
>
> MR. CONROY: Because we must design a system that's operable for conditions that the operators will, in fact, face. It's not an operable system if the operators are looking at low voltages below criteria or overloads beyond our emergency ratings which also may -- not may, if there are overloads and they're due to the conductor thermal limit, they'll also be violating National Electrical Safety Code ground clearances. That's not a system we can hand over for the operators to operate. We need -- if they -- we see a problem, we need to fix it.
>
> MR. DES ROSIERS: And why is that? If you just ignore it and say we have made the decision that our lower-voltage system will be less reliable, we'll just -- there will be certain things that will happen, what is the significance for the operator who is faced with that scenario now in real time, when that -- that confluence of events has caused that scenario to actually occur?
>
> MR. CONROY: So in other words, in the do-nothing scenario, let the system violate criteria, what is the consequence of that?
>
> MR. DES ROSIERS: The planners have ignored it, but now it's the operator faced with that scenario. What is the significance from the operator's perspective?
>
> MR. CONROY: Depending on exactly what the violation is and how bad it is, we could do damage to our equipment or customer equipment due to low voltages. If the voltage is sufficiently low to cause motor stalls, ultimately we could see local voltage collapse which we don't know where it stops. Depending on how bad the overload it, we could damage our equipment or we could -- if -- depending on how bad the overload is, we could violate NESC safety clearances or, if it was bad enough, actually have wire contact with whatever's underneath the wires.
>
> MR. DES ROSIERS: And -- and the operator -- under all those scenarios, the things that can happen, can the operator ignore it?
>
> MR. CONROY: No.

MR. DES ROSIERS: And when the operator acts, does something to address it, what then is the significance to the rest of the transmission system, both at the lower-voltage level and at the BES level?

MR. CONROY: If we don't fix it, we don't know what happens. We don't -- I -- I'm not sure what the operator action would be and what the consequence would be. Like I said, for instance, if our -- if we had studied it ahead of time and found the solution to be opening a breaker to interrupt the line that had the overloads, if we had studied that ahead of time, found that was effective, and found there was no impact on the BES, then we would know. If we ignore it, we don't know. So the operator may take an action that may have an impact on the BES, but he has to take an action that will solve the problem then and there.

MR. DES ROSIERS: That's all I have, thank you.

MR. WELCH: Just one short follow up, and I -- I'm -- I am not leading into a debate about whether it's a good idea to do something or a bad idea to do something or whether the operators will be happy or unhappy or, indeed, whether the line will not fall and sag and do something dreadful. But I -- I think Jared actually provided a very useful description of two kinds of effects that you see in the 34 kV system based on the testing you do. In -- in one case, it has an effect or could have an effect on the BES, and in that case, I think your testimony is you go to NERC jail if you don't plan to solve it. But in the second case, I -- I heard your answer to be somewhat different, and that is you may not go to NERC jail, but lots of bad things happen and we don't want those bad things to happen. So is that a fair characterization of those two different situations?

MR. CONROY: Yes.

MR. STINNEFORD: I guess, with the caveat that in the second situation, we may still go to NERC jail if -- if the consequences are things that we had not modeled, including operator actions --

MR. WELCH: If you didn't see them in the first -- in the first kind of study -- I understand your point that if you are wrong about whether it has an effect on BES, then if it actually does have an effect on BES, you could be found to have not planned appropriately. But at least in the theoretical case where you -- you know with a very high degree of certainty this is a bad effect, but it's not going to affect the BES, that -- that -- even though there could be all kinds of good reasons for planning the system and building it to avoid that communicate, it wouldn't be considered an NPCC or NERC violation not to have planned to relieve that.

MR. STINNEFORD: I think there's still some question about what the fallout's going to be from the Southwest Blackout Report.

MR. WELCH: Okay, that's a fair question.

> MR. BERGERON: I'd just ask one thing, one clarifying question on that point. So if you do your testing and you're in Jared's first hypothetical where -- where you find, in fact, that something on the 34.5 bounces back and affects the bulk, don't you have a responsibility at that point to request reclassification of those facilities?
>
> MR. CONROY: I would say we either have to request a reclassification of those or fix it. The reason I say either because the reclassification would actually end up worse from a -- how much money we have to spend and what level of design standard the 34 kV system must be designed to because right now we have a lower standard for the 34 kV system design. It's only single-element contingencies on maintenance outages that are planned maintenance at lower loads. As soon as we classify that as BES, we'll have to do multiple-element contingencies on the 34 kV and we'll have to do N-1-1 at peak load for unplanned outages sequentially. So that's the impact of the reclassification. So what I would look to is fixing a problem, rather than reclassifying it.

(10/26/12 Tr. at 98:13-102:12.)

In short, fixing such violations (i) ensures that CMP's entire transmission system can operate reliably and safely under the tested conditions mandated by NERC, NPCC and ISO-NE, (ii) ensures that the CMP operator actually faced with these conditions does not take any action on the sub-transmission system (such as opening a parallel path 34.5 kv line and thereby shifting additional flow back to the compromised BES) that itself <u>will</u> impact the reliability of the BES, and (iii) simply constitutes good utility practice. CMP urges the Commission to agree, particularly given the very real question under federal law discussed immediately below as to whether the Commission can mandate that CMP apply less rigorous planning standards to its sub-transmission system.

IV. PREEMPTION

In its July 13, 2012 Comments, CMP raised its concern that the Commission does not have jurisdiction to impose mandatory transmission planning standards on CMP and the other Maine utilities. The Hearing Examiners deferred consideration of this issue until this stage of the proceeding. During the hearing, Chairman Welch also asked several questions related to this issue. The following discussion reiterates CMP's view of the applicable federal law, which preempts the Commission from dictating the standards CMP and the other utilities must use to plan their non-BES/PTF transmission facilities, and also provides CMP's response to Chairman Welch's questions including his proposal that the Commission establish a "safe harbor" to avoid future disputes with respect to the planning and approval of sub-transmission facilities.

A. In the federal-state division of regulatory authority over transmission facilities, the state participates in the federal transmission standard-setting process and, to the extent consistent with federal law, regulates local siting.

The scope of federal control over transmission and the concomitant role of state regulatory commissions is governed by the Federal Power Act, 16 U.S.C. §§ 824 *et seq*. (FPA). The most relevant FPA sections with respect to local transmission planning are FPA §§ 201 and 215, although other sections, such as Sections 205 and 206, also shed light on this issue.

1. Under FPA § 201, all of CMP's transmission facilities fall under exclusively federal jurisdiction.

a. Under Section 201, FERC regulates transmission.

16 U.S.C. § 824(b) draws the federal-state jurisdictional line between facilities for transmission or sale of electric energy in interstate commerce (federal), and facilities used in local distribution or only for the transmission of electric energy in intrastate commerce (state or local). The Supreme Court has indicated when jurisdiction is federal, that jurisdiction is exclusive. *New England Power Co. v. New Hampshire,* 455 U.S. 331, 340 (1982) ("Congress enacted Part II of the Federal Power Act …, which delegated to the Federal Power Commission, now the Federal Energy Regulatory Commission, exclusive authority to regulate the transmission and sale at wholesale of electric energy in interstate commerce.").

There is no transmission only for intrastate commerce in CMP's service territory. Hence, <u>all</u> of CMP's transmission lines fall within exclusively federal jurisdiction.

b. **Historically, local authorities have exercised authority over siting issues, including transmission.**

Despite the apparently black-and-white nature of this divide, historically, issues regarding the siting of facilities, including transmission, have been left to the states. This tradition is indirectly reflected in FPA § 216, 16 U.S.C. § 824(p), which affirmatively provides for federal intervention in transmission siting when it is in the national interest to establish electric transmission corridors.

Thus, looking solely at Section 201, transmission planning decisions, except perhaps the choice whether or where to site new facilities, is a federal interest, governed by FERC and its delegated authorities. State intrusion in this area is both field and conflict preempted.[13]

2. **Consistent with FPA § 201, FPA § 215 extends federal control over all facilities affecting reliability of the "Bulk Power System".**

FPA § 215, 16 U.S.C § 824*o*, gives NERC and ultimately FERC the power to ensure reliability of the "bulk power system" (BPS). Section 215 thus confirms the federal interest in planning the reliability of the interconnected grid.

Section 215(i)(3) provides that "[n]othing in this section shall be construed to preempt any authority of any State to take action to ensure the safety, adequacy, and reliability of electric service within that State, as long such action is not inconsistent with any Reliability Standard…." At first blush, this language could suggest that a state commission <u>can</u> act in the area of safety,

---

[13] There are two types of preemption, explicit and implied. "Express preemption occurs to the extent that a federal statute expressly directs that state law be ousted to some degree from a certain field. " *Jones v. Rath Packing Co.,* 430 U.S. 519, 525 (1977). State regulation may be implicitly preempted through either field preemption or conflict preemption. *Gade v. National Solid Wastes Management Ass'n,* 505 U.S. 88, 98 (1992). Field preemption occurs when "the scheme of federal regulation is so pervasive as to make reasonable the inference that Congress left no room for the States to supplement it. " *Rice v. Santa Fe Elevator Corp.,* 331 U.S. 218, 230 (1947) (citations omitted). Conflict preemption occurs either when "it is impossible for a private party to comply with both state and federal requirements, " *Florida Lime & Avocado Growers, Inc. v. Paul*, 373 U.S. 132, 142-43 (1963), or when "state law stands as an obstacle to the accomplishment and execution of the full purposes and objectives of Congress. " *Freightliner Corp. v. Myrick,* 514 U.S. 280, 287 (1995).

adequacy or reliability as long as it is not conflict-preempted. This would seem, in turn, to modify the exclusive, field-preemptive nature of federal control over transmission facilities under Section 201.

But FERC has explained that Section 215(i) is "not a grant of new authority to the states, but merely preserve[s] any authority states may have under state law." *Midwest Indep. Transmission Sys. Operator, Inc.*, 122 FERC ¶ 61,283 at P. 58. Section 215(i) alludes to local authority over "electric service." To read Section 215 harmoniously with Section 201, Section 215(i) merely confirms that a state commission may regulate issues such as reliability of distribution equipment – but even then, within that local facility bailiwick, the commission cannot issue an order inconsistent with a federal reliability standard.

Thus, Sections 201 and 215 together reflect federal regulatory control over all transmission except that expressly carved out in Section 201, of which CMP has none.

Other language in Section 215 confirms that federal preemption extends to FERC-jurisdictional facilities, broadly defined. The BPS referenced in Section 215 is broader than the current definition of BES, to which NERC says its Reliability Standards apply. *See* FERC Order 693, ¶ 76 ("the Bulk-Power System reaches farther than those facilities that are included in NERC's definition of the bulk electric system."). Section 215(a)(1) defines BPS as "facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof). The term does not include facilities used in the local distribution of electric energy." 16 U.S.C § 824*o*(a)(1)(emphasis supplied). Hence, while retaining the carve-out of federal control over distribution, BPS is defined as anything "necessary for operating" the interconnected network, or any portion thereof.

Similarly, Section 215(a)(3) defines "reliability standard" as a requirement, approved by FERC under this section, "to provide for reliable operation of the bulk-power system." 16 U.S.C § 824*o*(a)(3). Again excepting distribution (which is neither BPS or BES, *see* FERC Order 743-A, ¶ 25), the ambit of federal control is defined as those facilities needed to provide for reliable operation of the BPS.

Other authority confirms the federal intent to reach beyond the BES to apply federal law over a broad category of facilities that are or affect the BPS. NERC's definition of BES pending final FERC approval draws the line at transmission facilities and interconnections operated at 100kV or higher (with certain inclusions and exceptions).[14] FERC Orders 743 and 743-A cited in the NOPR directed NERC to adopt 100 kV as threshold, but invited alternative proposal from NERC if equally or more effective. Order 743 includes broad language regarding the goal of ensuring that "facilities that could <u>significantly affect reliability</u> are subject to mandatory rules." (Order 743, 133 FERC ¶ 61,150 at P 2 (2010) (emphasis supplied). Thus, however BES is defined, the federal interest is identified in the statute as the BPS, and FERC confirms that the federal objection is to regulate facilities affecting reliability of the BPS.

Notably, if some transmission facilities not deemed BES do not meet NERC Reliability Standards, they can exacerbate outages on the BPS. *See e.g.* Southwest Blackout Report. It is for this critical reason that, consistent with the statutory language noted above, federal authority reaches beyond the BES to equipment affecting BPS reliability.

The NOPR accordingly includes language underscoring the need to federally regulate all equipment affecting the interconnected system, excluding distribution:

[14] *Revisions to Electric Reliability Organization Definition of Bulk Electric System and Rules of Procedure,* Notice of Proposed Rulemaking, 139 FERC ¶ 61,247 (June 22, 2012) (NOPR).

- ¶ 106…. we note that while establishing a "bright-line" threshold of 100 kV has significant advantages, it may not capture all facilities that are <u>necessary for the operation of the interconnected transmission network</u> that fall below that threshold. As the Commission indicated in Order No. 743 and Order No. 743-A, its goal is that the definition of bulk electric system should include <u>all facilities necessary for the operation of the interconnected transmission network, except for local distribution</u>….

- ¶ 107. Recent events reinforce the Commission's statements in Order Nos. 743 and 743-A with respect to ensuring that sub-100 kV facilities, as appropriate, are included in the bulk electric system. The September 2011 Blackout Report concluded that certain sub-100 kV facilities, which were not designated as bulk electric system facilities, contributed to the cascading blackout affecting San Diego, California …

Transmission planning involves considerations relating to both operating and building facilities. Reading the relevant legal authority harmoniously, planning is primarily an operational, federally governed issue to the extent the question goes to the reliability of the interconnected system, because reliability of the interconnected grid is a primary federal objective under the FPA. Siting new facilities is only one step that can be taken for ensuring reliability.

Hence, the state does not have any separate regulatory role in setting standards to determine whether the existing transmission system is reliable, or what the menu of options may be to ensure that reliability as measured by federal standards, even if the state has the ability in certain contexts, under certain circumstances, to veto the siting of new transmission facilities as the method to achieve reliability as determined under federal standards.

Further evidence of the lack of a state role in regulating transmission planning except the specific transmission identified in FPA § 201 is reflected in the fact that the need for transmission upgrades is reviewed under FERC-approved ISO-NE agreements and tariffs through a regional, collaborative process that expressly provides mechanisms for state commission participation within that process. Also, if a state commission believes that a system provider is gold-plating any aspect of its transmission system, the commission can oppose the upgrades in a Section 206 rate proceeding before FERC. 16 U.S.C. § 824*e*.

Thus, the federal framework specifically provides a role for state commission participation in setting transmission standards, but as a stakeholder participant in dialogue, not as a regulator.

B. Given the federal-state division of regulatory authority over transmission facilities, guidance from this Commission as to its perspective on appropriate local planning standards could be helpful as a practical matter to identify a "safe harbor" of pre-approved measures to ensure reliability.

1. Local planning standards are delegated under federal law to transmission providers.

Federal law governing transmission planning includes the substantive standards set by NERC (its Reliability Standards specifically applicable to the BES), as well as substantive ISO-NE rules, which are themselves enforceable rates, to which the filed rate doctrine applies.[15]

Federal law also includes what the local utility deems good planning practices, pursuant to the delegation by federal law of decision-making to these utilities. *See* Order 890-A, ¶ 188 ("Transmission planning is the tariff obligation <u>of the transmission provider</u>, and the pro forma OATT planning process adopted in Order No. 890 is the means to see that it is carried out in a coordinated, open, and transparent manner.") (emphasis supplied); *see also* Order 890, *Preventing Undue Discrimination and Preference in Transmission Service* ¶ 440 (2007) ("in

[15] Consistent with the bright-line jurisdictional divide in FPA § 201, pursuant to FPA §§ 205 and 206 (16 U.S.C. §§ 824*d* and 824*e*), FERC regulates all transmission rates. Under §§ 205 and 206 of the FPA, rates filed or fixed by FERC "must be given binding effect" by the state agency. *Nantahala Power & Light Co. v. Thornburg,* 476 U.S. 953, 962 (1986). These rates have the legal effect of regulations. *California ex rel. Lockyer v. Dynegy, Inc.*, 375 F.3d 831, 839 (9th Cir. 2004) (once filed with FERC, the tariff in a contract constitutes "the equivalent of a federal regulation") (citation omitted). *Cf. Marcus v. AT&T Co.,* 138 F.3d 46, 56 (2d Cir. 1998) ("filed tariffs have the force of law and are not simply contractual") (citation omitted). "Rates" are defined broadly, and are not limited to rates *per se*, but include utility practices that affect rates. *Nantahala Power*, 476 U.S at 966 ("the filed rate doctrine is not limited to 'rates' *per se*: our inquiry is not at an end because the orders do not deal in terms of prices or volumes of purchase.").

many cases, RTO planning processes may focus principally on regional problems and solutions, not local planning issues that may be addressed by individual transmission owners.") (emphasis supplied).

Thus, Attachment K – Local of the FERC-approved tariff requires adoption of the plan through a local system planning process that provides for stakeholder input, including that of the state regulator, but this federal framework delegates the ultimate decision-making to the utility in that local system planning process, and the decision made by the utility applying that process should be deemed as preemptive as if FERC approved the decision itself directly. *See Entergy La. Inc. v. La. PSC*, 539 U.S. 39, 50 (2003) ("It matters ... only whether the FERC tariff dictates how and by whom [the] classification should be made.").

Viewing this issue from the perspective of the filed rate doctrine and the exclusive federal control over transmission rates broadly defined, the applicable rates here consist of CMP's local network service rate, calculated under CMP's standards set under its local system plan under Attachment K – Local, and the CMP's Local Service Rates are part of ISO-NE's approved OATT. *See* Letter Order, *ISO-New England*, ER12-1421-000 (May 4, 2012) (accepting ISO-NE OATT Sched. 21-CMP for filing). The Transmission Operating Agreement (TOA) is filed with, and approved by, FERC. *ISO-New England*, 109 FERC ¶ 61,147 (2004). Schedule 21-CMP, Att. F (Local Network Operating Agreement), § 1.4 provides that a local transmission customer "shall operate all of its equipment and facilities connected to Central Maine's Transmission System, either directly or indirectly, in a safe, reliable and efficient manner. Such operations shall also conform to Good Utility Practice and all requirements and guidelines of Central Maine, the Control Area Operator, NERC and NPCC." (emphasis supplied). *See also* TOA at § 3.09 ("Each PTO shall engage in planning for its Local Area Facilities in a manner that is consistent with applicable NERC/NPCC Requirements, Good Utility Practice and the ISO OATT.").

In sum, this federal framework, with some transmission planning standards set by NERC and the remaining local standards by the transmission provider, consistent with the regulatory divide outlined in Section A, *supra*, leaves no regulatory role for a state commission in setting transmission standards, with the exception of that transmission expressly excepted from federal jurisdiction in FPA § 201. It is certainly clear that NERC Reliability Standards apply to the BES, which will include, at a minimum, most 100 kV+ and higher voltage facilities once FERC approves the change in the definition of BES. While someone might argue that the state may also apply its own reliability rules if there is no conflict with the NERC rules under Section 215, as noted above, the better view is that this conflict-based preemption approach applies only to non-FERC jurisdictional facilities. In any event, if a state required the application of a more lax standard than the federal standard, and the higher standard were needed to operate the BPS reliably, that would be a conflict, and deemed so even when the applicable federal standard is the local utility's as determined by that utility as authorized under the ISO-NE rules and tariffs which themselves constitute preempting federal regulation.

2. While the state does not set transmission standards, local or otherwise, an important role remains for the state commissions to advise on their views as to the appropriate local transmission planning standards.

Recognizing this federal-state division of authority does not mean that there is no role for a state commission to play regarding local transmission planning aside from stakeholder input in ISO-NE planning processes. To the contrary, Commission guidance as to its views on local planning standards could be helpful in avoiding unnecessary and potentially costly disputes and assisting CMP (and the other Maine utilities) in its identifying and applying its good utility practices.

As a threshold matter, there are various mechanisms to resolve disputes over whether a state has enforceable powers over a decision related to local transmission planning, including as noted above Section 206 proceedings. There are dispute resolution mechanisms in the ISO-NE planning process. FPA § 215(i) also provides that NERC or affected parties may file a petition with FERC to obtain an order determining whether the action of a state commission is inconsistent with a Reliability Standard. 16 U.S.C. § 824o(i)(4). NERC Rule of Procedure § 314 provides that a system owner must promptly tell such state commission, NERC and ISO-NE of such a potential conflict.

But it behooves all stakeholders to avoid these costly and time-consuming litigation avenues when possible. Also, while state commissions lack authority to set enforceable transmission planning standards, they could potentially use their siting authority to block or attempt to block approaches to resolving reliability concerns that involve siting new facilities. Hence, at a minimum, it is better for all concerned that the state commission's views on local planning issues be clear, to facilitate avoiding conflict when possible. Everyone has the same goal: a reliable grid. No one wants to spend time and money arguing over jurisdiction if the interested parties can come together on mutually acceptable approaches to ensuring grid reliability.

CMP therefore encourages this Commission to identify the transmission planning standards pursuant to which the Commission will sign off on future upgrades of transmission facilities (assuming such upgrades are deemed appropriate under federal standards). Chairman Welch floated that the Commission could do so through a "safe harbor" whereby the utilities would know that if they planned their non-BES transmission facilities in accordance with the safe harbor planning standards articulated in this proceeding the Commission would not later challenge (presumably as part of any CPCN proceeding or otherwise) the transmission upgrade on the grounds that the planning standards used to justify the need for the upgrade were inappropriate in any way. However, should a utility seek to justify a transmission upgrade by reference to a more stringent planning standard, then that utility would have to make some sort of cost/benefit analysis supporting why the more robust upgrade is appropriate under the circumstances, including that it provides increased reliability and/or longevity or other benefits such as increased support for renewable generation development for a modest additional cost.

While such state-approved safe harbor cannot comprise enforceable regulation, such a transparent, pre-existing set of Commission approved standards could be a beneficial outcome of this proceeding. As Eric Stinneford testified during the hearing (10/26/12 Tr. at 45:5-7.), such a safe harbor approach would be better than the current state of affairs where the planning standards used to justify transmission upgrades are repeatedly scrutinized in every CPCN proceeding, such that those proceedings are increasingly time consuming, repetitive and expensive. Knowing definitively the Commission's position with respect to the remaining planning standards in dispute would help streamline future CPCN proceedings such that hopefully they could be completed within the six month statutory period, 35-A M.R.S. § 3132(2), by reducing, if not eliminating, the fights over the appropriate planning standards. Such regulatory certainty would also encourage the utilities to act outside the safe harbor only when truly necessary in their view to ensure reliability of the interconnected grid. Moreover, for those instances where the utility does conclude that it is necessary to plan outside of the safe harbor, a clear delineation of the factors the Commission would consider to find a "public need" for the proposed upgrade under 35-A M.R.S. § 3132(6) would further focus the issues in any subsequent proceeding.

V. CONCLUSION

CMP very much appreciates the Commission's effort to investigate what standards and criteria are appropriate for planning Maine's lower voltage transmission system and shares the Commission's goal of avoiding continued ad hoc fights over those standards in future proceedings. Regulatory certainty is beneficial to the Commission, Maine's three T&D utilities and all other interested stakeholders as all work to ensure that Maine's transmission system provides reliable and cost-effective service for Maine customers. CMP is pleased that agreement has been reached on the several points discussed above and requests that the Commission adopt each of these points in its final order. CMP also believes that the record developed in this investigation supports CMP's position with respect to the handful of issues that remain in dispute and requests that the Commission find CMP's planning assumptions and practices with respect to these issues are reasonable and appropriate. These assumption and practices which reflect good utility practice and the sound professional judgment of its transmission planning engineers, are designed to permit CMP to cost-effectively plan its transmission system to remain reliable over the planning horizon across a wide spectrum of possible future scenarios in conformity with all applicable federal and state laws and regulations.

Respectfully submitted,

Jared S. des Rosiers
PIERCE ATWOOD LLP
Merrill's Wharf
254 Commercial Street
Portland, ME 04101
(207) 791-1100
Attorney for Central Maine Power Company