ELECTRONICALLY FILED ON OCTOBER 26, 2009

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

RE: CENTRAL MAINE POWER CO. & PUBLIC SERVICE OF NEW HAMPSHIRE  
Request for Certificate of Public Convenience & Necessity for the Maine Power  
Reliability Program Consisting of the Construction of Approximately 350 Miles of  
345 kV Transmission Lines, Docket No. 2008-255

THIS IS A VIRTUAL DUPLICATE OF THE ORIGINAL HARDCOPY  
SUBMITTED TO THE COMMISSION IN ACCORDANCE WITH  
ITS ELECTRONIC FILING INSTRUCTIONS

Dear Karen,

Attached is a redacted version of Peter Lanzalotta's October 23, 2009 testimony. The redactions were made at our request by CMP. The information is protected under Protective Order No. 2 as it is considered Critical Energy Infrastructure Information.

We will send copies of this redacted testimony to all parties.

We are also sending copies of the confidential version of this testimony to those parties who have executed CMP’s non-disclosure agreement.

Thank you for your attention to this matter,

Very truly yours,

[Signature]

EJB/dt
Enclosure: Redacted Testimony of Peter Lanzalotta
cc: Service List
STATE OF MAINE
PUBLIC UTILITIES COMMISSION
Docket No. 2008-255

CENTRAL MAINE POWER COMPANY
and
PUBLIC SERVICE OF NEW HAMPSHIRE
Request for Certificate of Public Convenience
and Necessity for the Maine Power Reliability Program
Consisting of the Construction of Approximately
350 miles of 345 kV and 115 kV Transmission Lines ("MPRP")

Direct Testimony

REDACTED PURSUANT TO PROTECTIVE ORDER NO. 2

Prepared by:

Peter Lanzalotta
Lanzalotta & Associates LLC
67 Royal Point Drive, Hilton Head Island, SC 29926

Prepared for:

The Maine Public Advocate
Richard Davies, Public Advocate
Eric Bryant, Senior Counsel
Agnes Gormley, Senior Counsel

October 23, 2009
Q. Mr. Lanzalotta, please state your name, position and business address.

A. My name is Peter J. Lanzalotta. I am a Principal with Lanzalotta & Associates LLC, ("Lanzalotta"), 67 Royal Point Drive, Hilton Head Island, SC 29926.

Q. On whose behalf are you testifying in this case?

A. I am testifying on behalf of the Maine Public Advocate.

Q. Have you previously submitted testimony in this proceeding?


Q. What conclusions did you state in your initial direct testimony in this proceeding?

A. My initial direct testimony stated the following conclusions:

i) The scope of the system reinforcements proposed in the MPRP is massive, substantially expanding the number of and the capacity of electric transmission system facilities in Maine.

ii) A primary factor driving the system reinforcement proposals of the MPRP is the fact that the various planning procedures, planning assumptions, and targeted levels of reliability used in the transmission planning process have been changed from what has been used in the past, in such a way that increases the apparent need for electric transmission system reinforcements.

iii) Without some of these planning changes, and taking into consideration more reasonable assumptions regarding available generation, interface loading, energy efficiency and demand response, the projected electric transmission system
reliability violations forecast for 2017 are greatly reduced in number from those
associated with the need for the MPRP. Conversely, using the planning
assumptions employed by CMP and ISO-NE, even the Maine electric
transmission system that exists today has several hundred apparent reliability
violations and many apparently unstable system scenarios at current load levels.

iv) A number of these changes go beyond what is specifically required by mandatory
reliability requirements. No attempt was made to justify these changes either on
an economic basis, or on the basis of past reliability shortcomings. No attempt
was made to determine the cost impact, or other impacts, of these changes, either
on a collective basis or individually.

It is not reasonable for the Commission to accept as a fait accompli all of these changes
in planning procedures, planning assumptions, and targeted reliability levels based on the
information provided by the Company. Judgments made by CMP and ISO-NE planners
pursuant to those areas of the minimum mandatory reliability requirements that allow for
the exercise of judgment should be evaluated and justified by the Company so that the
Commission has some basis on which to judge the reasonableness of these changes.

Q. What is the purpose of your testimony?

A. The purpose of this supplemental direct testimony is to address the progress in this
preceding, made since I filed my direct testimony in late January, 2009, in evaluating the
need for reinforcement of the Company’s transmission system in Maine at various load
levels and under various planning assumptions and to offer an opinion as to the need for
transmission system reinforcement.
Q. What conclusions have you reached as a result of the progress in this proceeding since you filed your direct testimony in January.

A. The single biggest area of disagreement that I have with the Company’s proposed system of reinforcements in MPRP deals with certain generation dispatch scenarios used to demonstrate a system planning need for transmission system reinforcement. In particular, the generation scenarios which start with all of the Westbrook and Yarmouth generation units shut down, i.e. D4 and SD4, seem particularly extreme, as this testimony will discuss.

Considering the reasonable dispatch scenarios, the group of transmission system reinforcements included in the Staff Alternative, as described later in this testimony, provides a reasonable transmission solution to the bulk of the system problems identified in the Company’s analyses.

Q. What progress has occurred in this proceeding since your initial direct testimony in late January, 2009?

A. On February 11, 2009, the Commission Staff called for a case conference, expressing concern that the Company’s direct case departs from the transmission planning assumptions that had been traditionally used, and that the Company had not convinced Staff that the planning assumptions that were used are required by NPCC, or that the Company’s proposals were reasonable or cost effective.
A case conference was convened at the Commission on 2/24/09 and 2/25/09 which resulted in the Company's agreeing to run additional load flow studies at three peak summer load levels: 1,600 MW, 1,800 MW, and 2,000 MW. The Company also agreed to use Staff assumptions regarding generation dispatch scenarios, interface transfer assumptions, equipment ratings, SPS availability, and other modeling assumptions.

Q. What is the significance of these peak load levels?

A. The original Needs Assessment in this proceeding was prepared using a 90/10 peak load forecast developed in the fall of 2006\(^1\). In this forecast, the projected peak load for 2009 was 1,886 MW, while the projected peak load for 2017 was 2,205 MW\(^2\).

Since that time, the projected peak load forecast has been decreasing. In the rebuttal testimony of John Davulis, the January 2009 90/10 peak load forecast predicts a 2009 peak load 1,729 MW, a 2017 peak load of 1,978 MW, and a 2018 peak load of 2,029 MW\(^3\). This 2017 forecast peak load of 1,978 MW represents a drop of 227 MW from the Fall 2006 forecast.

Peak loads have continued to drop, even below the reduced expectations of January 2009. The 2009 actual summer peak, adjusted to 90/10, was 1,625 MW. Compared to the 2009 peak load that was forecast in fall of 2006, the actual 90/10 peak load of 1,625 MW in 2009 was smaller by 261 MW.

These decreases in summer peak forecast loads for the present and the future reduces

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\(^1\) Volume I, Petition, p.25

\(^2\) Exhibit B-2, p.7

\(^3\) Davulis Rebuttal Testimony, March 19, 2009, p.16
some of the need for transmission system reinforcements that occurs within the typical
ten year planning horizon and pushes some of the needs out past this planning horizon.

Q. What generator dispatch scenarios were used for these additional runs?

A. The table below, excerpted from the Company’s 8/26/09 study of the Staff Alternative
transmission system reinforcement proposal, reflects the generation dispatch scenarios
requested by Staff.
Each of the first three scenarios models a major generating plant as not in service.

The 4th scenario, SD4, was modeled to reflect MPRP dispatch D4, and models the following stations as being out of service:

I note that in the recent transmission line proceeding regarding a new CMP 115 kV transmission line in the Saco Bay area, it was determined that ISO NE has a two-generator-out assumption that is used to stress the regional system for transmission planning studies4. This assumption was also discussed in prior technical conferences in this MPRP docket. The SD4 scenario goes well beyond a two-generator-out assumption.

Considering that CMP’s actual unadjusted 2009 summer peak load for the entire service area was 1,565 MW, one can see that defining a base case for transmission studies that begins with 1,430 MW of generating capacity in CMP’s service area deemed out of service represents an overly severe test for the transmission system.

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4 Examiner’s Report, Docket No. 2006-487, p.17
Q. What is the significance of generator dispatch scenarios to the determination of whether transmission system reinforcement is needed, and, if so, how much?

A. The choice of generation dispatch scenarios to use in the load flow modeling is one of the primary factors in determining the need for transmission system reinforcement. Existing transmission systems from the vertically-integrated era of investor-owned electric utilities were largely designed to connect each utility's electric generating units to that utility's electric load centers. Maine's electric generating units are no longer owned by the utilities that own the electric transmission system, such as the generating units in CMP's service area. But, the historical transmission system is still primarily designed to serve Maine loads from Maine generating units.

It is worthwhile noting that, while Westbrook Energy Center ("WEC") was developed as merchant plant, its location in CMP's grid is consistent with where CMP could have been expected to locate it, if it had built it. The WEC is located close to a major load center, near the junction of two gas pipeline facilities, and close to a major transmission substation, i.e., South Gorham.

When transmission system modeling is done with a generation dispatch scenario that shuts down seven of the generating units in a specific area, especially an area close to a load center such as Portland, it is not surprising that the transmission system is found to need reinforcement in order to meet reliability planning standards. However, that does not make it a reasonable determination of what is really needed. The generation dispatch in SD4, based as it was upon MPRP dispatch D4, goes beyond what is reasonable.
Q. After the Company evaluated the scenarios proposed by Staff, how did this process progress?

A. After the evaluation by the Company of the scenarios proposed by Staff, the following list of transmission system reinforcements was proposed by Staff in order to address the violations revealed:

The Company then evaluated these reinforcements using the Staff modeling assumptions, and found that there were still some remaining transmission planning violations. These were reflected in a Company handout, dated 7/29/09, describing the Staff Alternative, which included the seven system modifications described above, and which listed eleven remaining system concerns, along with proposed solutions for many of these concerns. These are listed in Table 1, below, which excerpts a portion of the Company handout.
Further refinement of the above proposed solutions resulted in the addition of a new 345 kV transmission line from
The additional reinforcements listed in Table 1, 

were made part of the Staff Alternative. As a result, the Staff Alternative now included the system changes shown in Table 2 below.

**Table 2**

**Q.** Were these reinforcements evaluated by the Company?

**A.** Yes. In a report dated 8/26/09, the Company presents data on the results of its evaluation of the proposed reinforcements included in the Staff Alternative, shown in Table 2 above. This evaluation was prepared at the peak load levels of 2,000 MW and, in addition, at 2,200 MW, so as to help determine the longevity of the Staff Alternative.
Q. What did this evaluation find?

A. With the exception of generation dispatch scenario SD4, the Staff Alternative eliminated virtually all of the DNS (did not solve) load flow results. At the 2,000 MW load level, the sole exception involves DNS and would need further review to determine whether a reconfiguration of the substation would be a sufficient remedy.

These are a number of what are mostly relatively minor voltage violations, mostly on the radial portions of the 115 kV system at the 2,000 MW peak load level, and several thermal overloads, also on the 115 kV system. Some additional reinforcements in the way of voltage support and thermal capacity at the 115 kV level would probably be needed.

At the 2,200 MW peak load level, if we eliminate the SD4 generation dispatch scenario, the number of DNS scenarios is the same as at the 2,000 MW peak load level.

Q. How does the estimated cost of the Staff Alternative compare with the the Company’s MPRP proposal?
The Company has developed an estimate of the cost to design, permit and build the Staff Alternative of approximately $777 million, comprised of about $515 million for transmission lines and $262 million for substations. 6

The Company cautions that several elements of the Staff Alternative were not part of the MPRP and, therefore, have less well-developed cost estimates. These elements may be subject to what the Company calls “substantial deviation from the values presented here, should detailed engineering be initiated.” 7 These elements include

The Company has also developed an estimated cost for the MPRP of $1.550 billion, or about twice the estimated cost of the Staff Alternative. The MPRP estimate includes about $1.152 billion for backbone facilities and about $360 million for non-backbone facilities. 8

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6 CMP filing of letter and attachments dated 8/28/09, Attachment 2, p.2
7 CMP filing of letter and attachments dated 8/28/09, Attachment 2, p.1
9 CMP filing of letter and attachments dated 8/28/09, Attachment 3, p.5 (first of three sections)
Q. How does the longevity of the Staff Alternative compare with that of the MPRP?

A. Given that the MPRP costs twice as much as the Staff Alternative, it should not be surprising that the MPRP may have more longevity than the Staff Alternative. However, the goal here should be to address the transmission system reliability planning criteria violations that are projected to occur over a reasonable planning horizon, typically ten years for transmission system planning. The Staff Alternative appears to accomplish this goal, and at substantially less cost than the MPRP.

Transmission system planning is an ongoing process, reflecting changes in load forecasts, generating unit additions, generating unit retirements, and other relevant factors on at least an annual basis. It is difficult enough to try to predict these factors even ten years into the future. Some may speculate that the MPRP will address system needs twenty or thirty years into the future. There is, in fact, no way to know what the system needs will be twenty or thirty years into the future, so to say that MPRP provides the proper facilities to meet these needs is highly speculative. In addition, by building transmission facilities today to serve system needs twenty or thirty years into the future, there is a risk that technological or other changes in the meantime could accelerate the obsolescence of these facilities.
Q. Did the Company study how many MWs of non-transmission alternatives ("NTAs")
would be needed in lieu of certain transmission system reinforcements in order to
maintain system reliability?

A. Yes. At the request of OPA, the Company undertook load flow analyses which assessed
the Staff Alternative without the proposed new 345 kV Orrington – Albion – Maxcys\textsuperscript{10}
transmission line and including the currently-operating special protection system. The
purpose of these analyses was to determine how many MW of non-transmission
alternative capacity, or other reinforcements, would be needed to meet reliability
planning criteria based on the dispatch and interface conditions specified by the Staff\textsuperscript{11}.
The proposed new 345 kV Orrington – Albion – Maxcys transmission line is one of the
more expensive components of the Staff Alternative.

The conditions modeled focused on several areas, the two most important of which are as
follows:

\textsuperscript{10} In the MPRP proposal, this line would run to Coopers Mill, a new substation in the vicinity of Maxcys.

\textsuperscript{11} MPRP – OPA Requested Analysis, 9/1/09
The Midcoast area is

Central Maine Power service area along the coast which is east of Wiscasset and south of Bucksport, Maine.\textsuperscript{12}

\textsuperscript{12} MPRP – Grid Solar Data Request for NTA Threshold Load Levels at 1,600 MW CMP Load, 9/1/09

\textsuperscript{13} MPRP – OPA Requested Analysis, 9/1/09

\textsuperscript{14} MPRP – OPA Requested Analysis, 9/1/09
The new 345 kV line was also intended to help address the uncertain system stability situation where the new Buxton to South Gorham 345 kV line and Section 386 (Buxton to Yarmouth 4) both suffered contingencies.
Q. Does this conclude your direct testimony?
A. Yes, at this time.