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")

Surrebuttal Testimony

REDACTED

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4. Attachment 4: ISO NE Economic Studies Working Group (ESWG), "Maine Power Connector Economic Analyses", May 22, 2008. Preliminary.

Introduction And Summary

Q. Please state your name, position and business address.

A. My name is Robert M. Fagan. I am a Senior Associate with Synapse Energy Economics, Inc., 22 Pearl Street, Cambridge, MA 02139.

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

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

Q. Did you file direct testimony on January 28, 2009 in this case on behalf of the Maine Public Advocate?

A. Yes.

Q. What is the purpose of this surrebuttal testimony?

A. The purpose of this surrebuttal testimony is to address certain aspects of the December 4, 2009 rebuttal testimony of CMP's witnesses Mr. Davulis and Mr. Dumais, Mr. Conroy and Mr. Conant, and Mr. Peaco and Mr. Hahn of LaCapra Associates. I also address Conservation Law Foundation (CLF) witness Mr. Tilghman's testimony on Maine wind issues, and I offer technical observations on the GridSolar proposal.

Q. Please summarize your testimony and recommendations.

A. In my direct testimony in January of 2009, I stated that CMP had failed to demonstrate a need for the MPRP. That remains the case. CMP's assertion of need for the totality of MPRP relies on outdated load forecasts and admits to excluding the effect of well over 200 MW of existing demand side resources on peak load. CMP also gives no weight in its need assessment to additional DR resource potential well into the hundreds of MW. CMP has conducted no analyses of the potential effect of order-of-magnitude lower-cost transmission reinforcement alternatives coupled with cost-effective demand-side resource implementation to relieve reliability concerns.

While advocating a need for transmission reinforcement to allow for wind energy development and interconnection, CMP has not analyzed the extent, location and timing of any such reinforcement need but instead claims a need for major interface reinforcement even though energy flow pattern projections reveal otherwise. I recommend CMP comprehensively analyze the extent, location and timing of transmission reinforcement needed to promote the state's wind policy goals. CMP's consideration of the potential value of future solar PV appears short-sighted, given the magnitude of declining cost projections and the distribution, sub-transmission and transmission system synergistic benefits.

I recommend that lower-cost transmission reinforcement alternatives should be analyzed by CMP using power flow analysis tools. Baseline power flow models should include a comprehensive combination of at least the following elements: i) demand response resource effects on peak load, ii) maximum achievable energy efficiency effects on peak load, iii) updated 90/10 load forecasts, iv) initial low-cost, high-impact transmission improvements (such as but not limited to load power factor correction, double circuit tower contingency removal, southern system improvements such as the South Gorham 2 autotransformer and a second 345 kV source into the Portland area), and v) 115 kV system improvements to support access to wind resources in Western Maine without necessarily increasing the thermal transfer capacity of the major Maine interfaces through extensive 345 kV system upgrade. A reasonable "stressed condition" dispatch or dispatches (i.e., generator availability) must also be used.

CMP's non-transmission alternatives assessment begins with a baseline needs analysis and corresponding "threshold load level"[1] inputs that do not include the effect of the second South Gorham autotransformer on CMP's southern system. It excludes the potential effect of other low-cost elements that would raise such threshold levels. This biases the model towards supply-side needs in excess of

[1] Threshold load level is defined in Exhibit I-3, the Non-Transmission Alternatives Assessment, at page 20/464. It is "...the target or threshold [load] level to which NTAs must reduce demand on the transmission system". Generally, reinforcement of the transmission grid leads to higher threshold load levels and lower amounts of subsequent NTAs required to maintain reliability.

what would be required for an NTA solution. Besides starting with these flawed threshold load level inputs, and underestimating the availability of demand response resources, the NTA model results are now also outdated because of FCM price projection and load forecast changes.

The single most glaring omission to CMP's analyses is excluding the effect of demand response resources on the peak load that CMP's transmission system is projected to bear. Existing, ISO NE FCM-cleared DR resources represent more than 15% of CMP's existing peak load yet they are not included as peak-load reducing effects in any of the core analyses to date. Addressing such resources in a separate NTA analysis artificially raises the true peak loading effects on the system that the power flow modeling tool evaluates, and creates a false sense of electrical need.

I summarize the body of my testimony as follows:

1. **Load Forecast Updates Shifts Original 2012 90/10 Peak in MPRP Filing by At Least Eight Years to 2020 or Later.** Review of CMP system load forecasts illustrates that projected 90/10 peak load for 2012 at the time of the MPRP filing (in July of 2008) will now occur (based on updated projections) no earlier than 2020, or at least eight years later than first thought. Together with consideration of the effect on the transmission system of i) demand response resource potential, and ii) maximum achievable energy efficiency resources, this illustrates that the MPRP need assessment is outdated. A revised need assessment with much lower "net peak load"[2] levels than have currently been modeled should be undertaken by CMP.

2. **No Demand Response in Need Assessment, and Too Little Demand Response Representation in NTA Assessments**. CMP's transmission need modeling includes no demand response resource effect. LaCapra's NTA Assessment did not reflect a sufficient level of demand response resource availability in Maine.

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[2] Net peak load is transmission system peak load net of the effect of energy efficiency, demand response and on-line distributed generation resources.

The existence of incrementally available DR in Maine (that did not clear the ISO NE forward capacity market) and the results of a recent (June, 2009) FERC Staff report including state-level assessment of demand response potential in Maine confirms levels of Maine DR in excess of that modeled in the NTA assessment.

3. **No Hybrid Solution Assessment and Outdated Power Flow Modeling Outcomes.** Contrary to LaCapra rebuttal testimony claims, to date there has been minimal analysis of "hybrid" solutions to reliability concerns. Reliability solutions consisting of combinations of the lowest cost transmission and non-transmission elements that would ensure Maine grid reliability have not been analyzed. These potential solutions should be analyzed and would directly include in the baseline power flow modeling the following: i) updated load forecasts, ii) demand response and energy efficiency resources, iii) certain transmission elements such as but not limited to the second South Gorham autotransformer, and possibly iv) the impact of future solar PV resources. When all of these reliability-affecting aspects of the Maine grid are considered, the results of CMP's power flow modeling exercises to date are seen to be at best outdated, and do not demonstrate MPRP need.

4. **Price separation in FCM Likely with NTA Approach**. LaCapra discounts the possibility of price separation in the ISO NE forward capacity market (FCM), even though the fundamental FCM market design tenets clearly point to such separation if an NTA approach were to be used to address reliability concerns. This is because an NTA approach is likely to further increase the level of "surplus" generation in the Maine capacity zone of the FCM. The NTA assessment presents no sensitivity analysis of such separation, and because of this it is at best an incomplete assessment of NTA solutions that fails to capture this important underlying dynamic of the ISO NE FCM. Given load and FCM changes since the July 2008 NTA assessment filing, and given other flaws in the

NTA methodology described in my direct testimony in January, 2009[3], the NTA assessment is outdated and needs to be redone.

5. **Implied Planning Reserve Margin for NTA Approach Too High**. The NTA assessment requires an overall supply reserve margin of 69% for the state of Maine. This is too high, and implies that the "threshold load levels" analyzed by LaCapra are too low, and/or the planning criteria used to determine NTA needs are too stringent.

6. **MPRP and Wind.** The MPRP analysis was not intended to serve as a transmission plan to develop and integrate Maine wind resources onto the grid. In this case to date, there has been no economic analysis of the effects of increased wind integration on the grid and minimal reliability analysis. There has been no comprehensive analysis of transmission needs to support Maine's wind integration goals. Preliminary analysis conducted by ISO NE in the Maine Power Connection case indicates substantial "energy headroom" across the major Maine interfaces in the absence of MPRP. While MPRP would increase thermal interface capacities in Maine, it is not clear that such increases are required to support expanded wind development and integration in the areas of Maine currently and likely to see expanded wind development. A revised transmission need assessment as noted in summary point 1 above should also explicitly address the overall economics of alternative transmission plans to support increased wind development in Maine.

7. **Grid Solar**. The GridSolar proposal is a fundamentally sound technical and conceptual approach to resolving electric reliability concerns in Maine. The GridSolar proposal is not "highly uneconomic and not financeable", as asserted by LaCapra. While there remains uncertainty associated with certain elements of the GridSolar proposal (as with the MPRP proposal), it is at least marginally economical when the financial model is run with reasonable assumptions. Based

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[3] As will be described, this includes primarily the use of "threshold load levels" that are too low, resulting in exaggerated need for NTA supply side resoruces.

on this result, solar PV resource options as a component of reliability solutions should not be summarily dismissed by CMP.

Load Forecast

Q. What does the latest update to the CMP load forecast show?

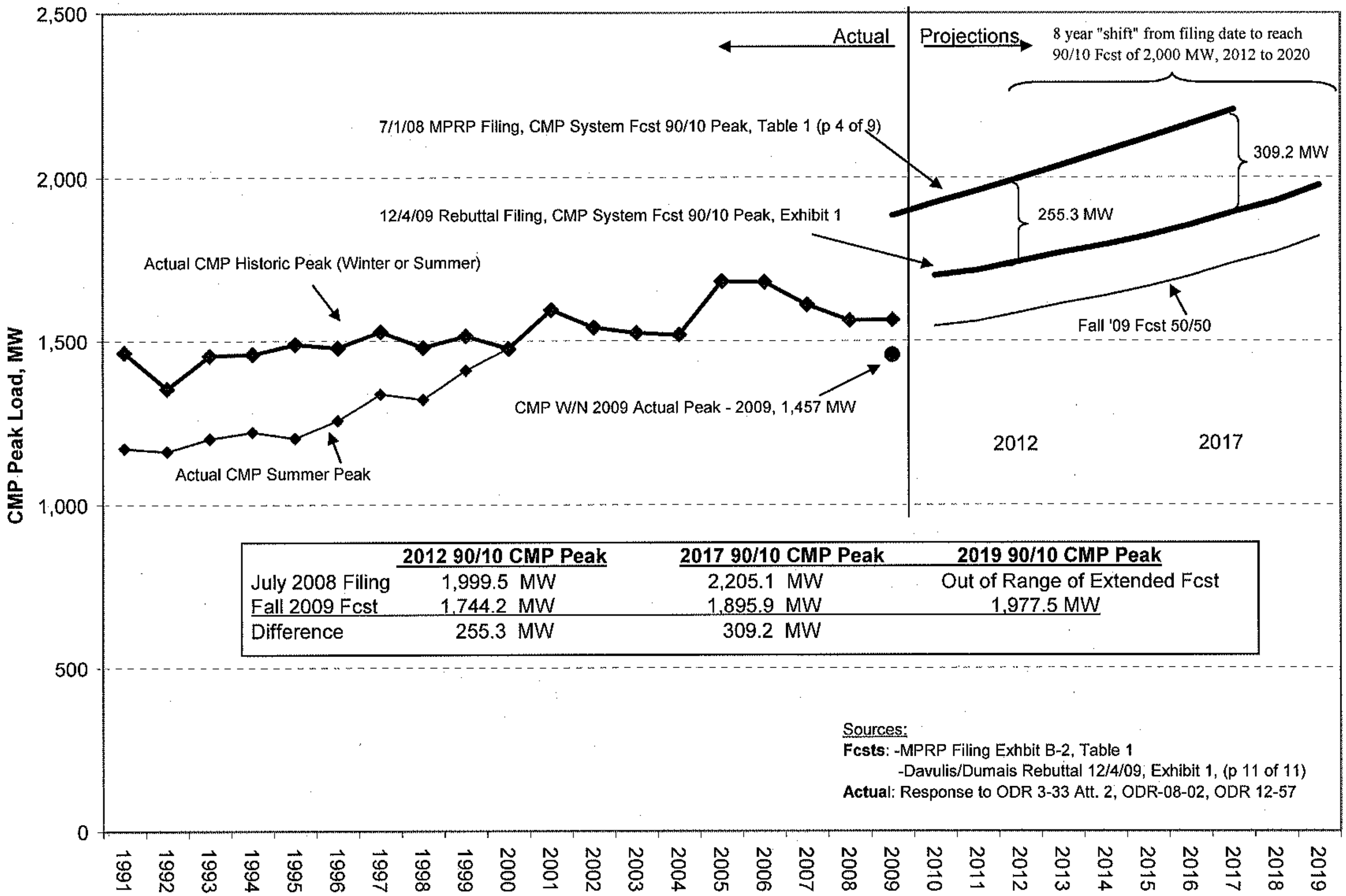
A. The latest forecast, when seen alongside prior forecast levels, shows a dramatic drop in CMP system peak load projection. The CMP system load forecasts illustrate that projected 90/10 peak load for 2012 at the time of the MPRP filing (in July of 2008) will occur no earlier than 2020, or at least eight years later than first thought. The projected 2012 90/10 CMP system load in the original filing was 1,999.5 MW. In the fall 2009 update, the projected 90/10 peak does not reach the 2,000 MW level at all in the period reviewed. It reaches 1,977.5 MW in 2019. Figure 1 below shows the pattern of CMP actual and projected peak loads, 1991 – 2019.

Q. What does this information illustrate?

A. It illustrates an eight-year shift in 90/10 peak load level compared to the original forecast accompanying the need filing in July of 2008. The originally forecast 90/10 load of approximately 2,000 MW in 2012 will not be reached until 2020. When coupled with peak load reduction from demand response resource availability, and further energy efficiency potential not included in the current forecast, the net peak load in 2020 would be further reduced by hundreds of MW, potentially below the 1,600 MW level even before any consideration of potential use of solar PV before the next decade ends. There has been no reliability analysis conducted at this load level for a transmission system with incremental improvements beyond just the second South Gorham autotransformer and load power factor correction.[4]

[4] The GridSolar-requested analysis conducted after the July 30, 2009 technical conference did not include any further transmission improvements and modeled additional net load from paper mill complexes.

Figure 1. CMP Actual and Projected Peak Loads, 1991 - 2019



Response to Rebuttal Testimony of LaCapra Associates

Demand Response Not in Transmission Need Modeling and LaCapra/GDS Significantly Underestimate Demand Response Potential in Maine

Q. What does the LaCapra rebuttal testimony say about demand response?

A. The testimony claims that the level of demand response originally estimated by GDS and contained in the NTA Assessment is valid.[5] The testimony sets out to refute my direct testimony concerning availability of a higher level of demand response in Maine.

LaCapra states at page 30

"The Fagan testimony also presents a comparison of the GDS demand response potential estimate to the results of the first two forward capacity market auctions held by ISO-NE, **and concludes that this comparison is evidence of significantly greater demand response potential in Maine than what is estimated by GDS.**" (emphasis added)

Q. Is this a correct characterization of your conclusion?

A. No. It mischaracterizes the thrust of my testimony on this point.

Q. Please reiterate the thrust of your direct testimony on this point.

A. My direct testimony at pages 38-42 states that

1) CMP has not incorporated any of the demand response resources into its transmission need modeling.

2) 192 MW of additional demand response resources that did not clear the FCM 2 auction could still be available for use as DR resources by CMP,

3) CMP had not adequately explored the availability of DR resources from larger customers in its territory.

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[5] LaCapra rebuttal testimony at page 30.

The first of these three points demonstrates the weakness of the CMP power flow model results that exclude even DR resources that already have cleared the ISO NE forward capacity market. The second and third points are evidence of existing DR beyond the level modeled by LaCapra in the NTA assessment.

My direct testimony then described the level of demand response resources used in the NTA assessment, and compared those to the results of the first FCM auction (Fagan direct, 43:14 - 44:13). In conducting that comparison I did not properly account for losses, reserve margin, and "gross-up" to the entire state of Maine.[6] Thus the actual amount of statewide demand response assumed in the NTA assessment for 2011 – 196 MW - is close to, yet still below, the levels cleared in the second FCM auction, which is 238 MW after accounting for emergency generation and Efficiency Maine resources, as noted by LaCapra.

I also noted in my direct testimony that the results of the second FCM auction included almost 200 MW of uncleared DR resources – again, proving the existence of DR in excess of that used in the NTA analysis.

The error I made in comparing FCM results to the level of DR modeled in the NTA analysis for 2011 does not change my conclusions on demand response and its impact on MPRP need. It does not alter the facts that

- demand response resources were not included in the need modeling;
- considerable demand response resource potential exists in excess of that modeled in the NTA analysis (and as I will next show, a new FERC report confirms this potential); and
- CMP has still not adequately explored the availability of DR resources from its larger customers.

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[6] As shown in the response to ODR-01-41, and as noted by LaCapra at page 30 of their rebuttal testimony.

Q. Please confirm that CMP does not include demand response resources in its transmission need models.

A. CMP does not include any level of demand response in its transmission needs assessment, either for 2012 or for 2017. It only includes the effect of existing Efficiency Maine energy efficiency programs. This has been confirmed by CMP.[7]

Q. Is additional information concerning demand response potential in Maine available since the filing of your testimony in January 2009?

A. Yes. FERC Staff released a report entitled "A National Assessment of Demand Response Potential", in June 2009. It is a 250-page report containing detailed demand response estimates by state, region, and sector.[8] It was prepared by The Brattle Group; Freeman, Sullivan & Co.; and Global Energy Partners, LLC.

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[7] Response to OPA 03-05; response to OPA-13-1(e).
[8] Available at http://www.ferc.gov/legal/staff-reports/06-09-demand-response.pdf.

Q. Does the LaCapra rebuttal testimony recognize the information available from that report concerning demand response potential in Maine?

A. No. Instead, the LaCapra rebuttal testimony references older reports and does not indicate an awareness of the June, 2009 FERC Staff report.[9]

Q. What level of demand response potential for Maine does LaCapra rely upon?

A. The LaCapra rebuttal testimony relies upon the GDS report, which indicates a demand response potential of 9.1% of peak load in 2017. Mr. Peaco and Mr. Hahn state that the GDS amounts are nearly twice as high as a recent EPRI estimate of demand response potential for 2020 of 4.6% of peak demand. They also refer to a FERC report from 2006, though it is not clear to which report this is in reference to.[10]

Q. What does the most recent FERC report state concerning DR potential in Maine?

A. The most recent assessment of national demand response potential, from June of 2009, identifies a level of demand response in each state in 2014 and in 2019. For Maine, the "BAU" or business-as-usual DR levels (which rely primarily on large customer DR potential) for 2014 are far above the GDS estimates supported by LaCapra. The report lists BAU levels of 510 MW of DR available in 2019. The GDS estimate for 2017 is 289 MW (response to ODR-41). Table 1 below shows the level of DR as a percentage of peak load for the BAU scenario and three successively higher levels of demand response.

[9] Mr. Hahn and Mr. Peaco confirmed at the December 2009 technical conferences that they did not have knowledge of this report.

[10] LaCapra rebuttal at 31-32.

Table 1. Demand Response Potential in Maine as a Percentage of Peak Load, per June 2009 FERC Staff Report

Cases:	Business as Usual	Expanded BAU	Achievable Participation	Full Participation
2014	17%	19%	20%	21%
2019	16%	19%	22%	24%

Source: National Assessment of Demand Response Potential, Maine values from Tables A-2 and A-3, "Potential Peak Demand Reduction by State", for 2014 (Table A-2) and 2019 (Table A-3) pages 81-82.

Q. What is the meaning of the four cases listed above?

A. The report states the following in regards to the meaning:

"Four scenarios have been considered in this analysis. The first, Business-as-Usual, is simply a measure of existing demand response resources and planned growth in these resources. The other three scenarios are measurements of demand response potential under varying assumptions. All three of the demand response potential scenarios are limited only to cost-effective demand response programs, meaning that the net present value of the benefits of a given program exceeds the costs.

Business-as-Usual (BAU) is an estimate of demand response if current and planned demand response stays constant. This scenario is intended to reflect the continuation of current programs and tariffs. In most instances, growth in program impacts is not modeled, although where information is available that explicitly states likely growth projections, that information has been included. The value in this scenario is that it serves as the starting point against which to benchmark the three other demand response potential scenarios.

Expanded BAU (EBAU) is an estimate of demand response if the current mix of demand response programs is expanded to all states and achieves "best practices" levels of participation, along with a modest amount of demand response from pricing programs and AMI deployment. The key assumption driving participation in the non-pricing programs is that all programs achieve participation rates that are representative of "best practices." This scenario provides insight regarding what could be achieved through more aggressive pursuit of programs that exist today. However, it does not account for those programs that are not heavily pursued today but have significant potential, such as residential dynamic pricing.

Achievable Participation (AP) is an estimate of demand response if AMI is universally deployed, dynamic pricing is the default tariff, and other programs are available to those who decide not to enroll in dynamic pricing. Customer participation rates were developed to reflect the reality that not all customers will participate in demand response programs. In this scenario, participation in dynamic pricing programs is not limited as it is in the EBAU scenario, and all demand response programs can be equally pursued. This scenario considers the potential inherent in all available demand response programs while restricting the total potential estimate to maximum participation levels that could likely be achieved in reality.

Full Participation (FP) is an estimate of the total amount of cost-effective demand response. This scenario assumes that there are no regulatory or market barriers and that all customers will participate. The value of this scenario is that it quantifies the upper-bound on demand response under the assumptions and conditions modeled in this Assessment."

Source: Report, pages 23-24 (footnotes excluded).

Q. Do you rely on the potential demand response available from AMI-initiatives in your analysis of CMP need for MPRP and the NTA Assessment?

A. No. When considering the level of reduced peak demand that could be seen on the transmission grid if DR resources were used by CMP, I rely on estimates of DR resources available from larger customers without AMI, and from automated/direct load control resources available across residential, small and medium commercial customers. These categories of DR are seen in the detailed summaries I reference below.

Q. What additional detail does the report provide for Maine demand response potential?

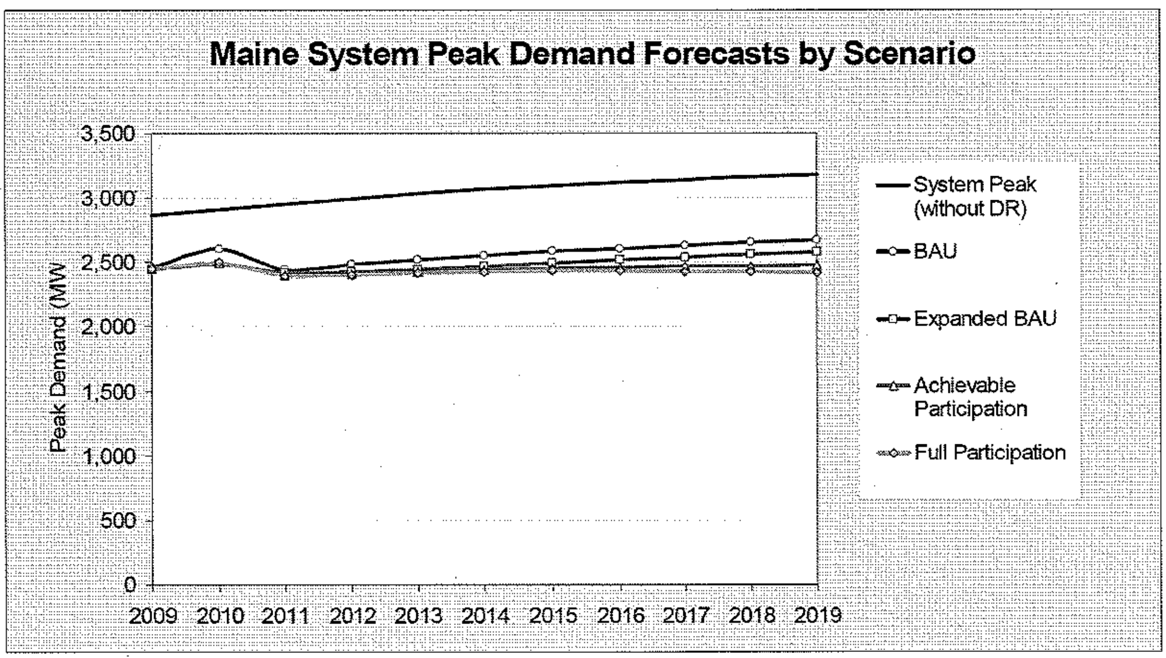
A. The report includes a detailed "state profile" listing for Maine that contains the following Table 2 and Figure 2:

Table 2. Demand Response Potential in Maine, from June 2009 FERC Staff Report

Total Potential Peak Reduction from Demand Response in Maine, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Automated/Direct Load Control	18	0.6%	0	0.0%	0	0.0%	0	0.0%	18	0.6%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	492	15.4%	492	15.4%
Total	18	0.6%	0	0.0%	0	0.0%	492	15.4%	510	16.0%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	2	0.1%	0	0.0%	1	0.0%	1	0.0%	4	0.1%
Automated/Direct Load Control	18	0.6%	1	0.0%	5	0.2%	0	0.0%	25	0.8%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	5	0.2%	78	2.5%	83	2.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	492	15.4%	492	15.4%
Total	20	0.6%	1	0.0%	12	0.4%	571	17.9%	604	19.0%
Achievable Participation										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	12	0.4%	12	0.4%
Pricing without Technology	53	1.7%	1	0.0%	23	0.7%	21	0.7%	99	3.1%
Automated/Direct Load Control	18	0.6%	0	0.0%	2	0.1%	0	0.0%	21	0.7%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	5	0.2%	78	2.5%	83	2.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	492	15.4%	492	15.4%
Total	72	2.2%	1	0.0%	31	1.0%	603	18.9%	706	22.2%
Full Participation										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	34	1.1%	34	1.1%
Pricing without Technology	71	2.2%	1	0.0%	39	1.2%	28	0.9%	139	4.4%
Automated/Direct Load Control	18	0.6%	0	0.0%	0	0.0%	0	0.0%	18	0.6%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	5	0.2%	78	2.5%	83	2.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	492	15.4%	492	15.4%
Total	89	2.8%	1	0.0%	45	1.4%	631	19.8%	766	24.1%

Figure 2. DR-Adjusted Peak Demand Patterns in Maine, from June 2009 FERC Staff Report



Source: A National Assessment of Demand Response Potential, Appendix A, Maine, pg 122. Maine pages are included as Attachment 1 to this testimony.

Q. Why are the peak load levels shown in the above graph seemingly quite high for Maine?

A. The data used in the FERC Staff report study include US DOE EIA data on electricity consumption and peak load. While the report does not point specifically to the exact source of peak demand, it appears that load currently served in Maine by self-generation – roughly 4 million MWH in 2007 – is added to the net peak load seen on the Maine transmission grid.[11] I also note that the Maine Public Service and Eastern Maine Electric Cooperative load is also included in these figures.

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[11]EIA "Maine Electricity Profile" data is available at http://www.eia.doe.gov/cneaf/electricity/st_profiles/maine.html

Q. What is the relevance of the DR potential level documented in the table and graph above?

A. Maine is one of the top three US states in demand response potential as a fraction of peak load[12]. The table above illustrates that Maine's DR potential, even under the least aggressive "business-as-usual" scenario, is significantly higher than the estimates used by GDS and supported by LaCapra in their rebuttal testimony.

Q. Does CMP account for this potential in their reliability assessments of need for MPRP?

A. No. As I originally stated in my direct testimony, CMP has not conducted any reliability need modeling that recognizes the contribution to peak load reduction that demand response resources would bring.[13] Rather, CMP treats the effects of DR outside of the primary analytical process used to defend MPRP need – they do not adjust peak load forecasts for the effects of demand response potential when conducting power flow modeling of the system. This singular analytical flaw renders much of the core analytical work conducted by CMP as highly suspect, since it does not reflect the use of any demand response resources, even those Maine resources that have already cleared the ISO NE FCM auction.

Q. How should CMP's reliability modeling address this demand response potential?

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[12] Maine is third in the US in terms of demand response potential as a percentage of peak load, according to the report: "Ranked by demand response potential as a fraction of peak demand, Connecticut, Maryland and Maine are highest; each has substantial amounts of existing demand response, Maine has an above-average share of peak demand in the Large commercial and industrial customer class, and Maryland has a relatively large amount of residential central air conditioning". (page 42)

[13] I note that PJM includes the effect of RPM (capacity market) cleared demand response in its load deliverability tests used as part of its transmission system planning, including an estimate of demand response resource levels in future years that is equal to the level secured in the most current year for which an RPM auction has been conducted. That is, PJM directly reduces 90/10 peak load forecasts by the level of cleared demand response prior to running its load flow models for "load deliverability" testing. See PJM manuals on the RPM capacity market (manual 18), and transmission planning (manual 14b), at http://www.pjm.com/documents/manuals.aspx.

A. The modeling should reduce the future-year peak load forecasts by some level of potential demand response to examine the remaining weaknesses in the transmission system after first accounting for the demand response resource.

Q. Please comment on DR resource use as a reliability resource.

A. Demand response resources can help ensure transmission system reliability by serving as a complement to transmission system improvements. In some instances they can help to defer or eliminate the need for certain transmission system improvements. If demand resources are used appropriately, they can reduce the net peak load seen on the transmission grid during the most stressful operating periods.

LaCapra states the following:

> "It must also be noted that the Demand Response resources needed as a reliability alternative to a transmission upgrade have different operability considerations that Demand Response resources needed for resource adequacy or FCAs. Demand Response resources used to meet resource adequacy needs are called upon only when ISO-NE is in a capacity deficit and invokes Operating Procedure No. 4. On the other hand, Demand Response resources deployed for reliability purposes are called upon when warranted by conditions on the transmission system even if there is a surplus of capacity. Thus, reliability Demand Response resources may be called upon more frequently, which could increase the compensation required to procure these resources or limit their effectiveness. These additional operability concerns would need to be addressed before relying on these resources as a replacement for the MPRP." (LaCapara at 32)

This concern is not new, and it must be taken seriously, but it does not mean that Maine DR resources would be unable to help system reliability because they might only be called during an OP-4 situation. It should be CMP's responsibility to explore the potential for Maine-based (or CMP-based) DR resources to help with system reliability even if that means proposing to contract for operation outside of the terms and conditions applicable to ISO-NE DR resources.[14] CMP has not met this responsibility.

Q. What evidence is there of CMP's efforts to investigate such resource options?

A. In response to OPA 13-1[15], CMP indicated that in February of 2009 it had conversations with three of the larger industrial customers, all of whom also happen to have on-site generation (CMP did not indicate that it explored DR options with any other large customers or customer groups). Based on the response to OPA 13-1 c., it appears that CMP has declined to have further dialogue with these customers concerning potential demand response provision apparently because these customers might not be positioned to respond to a transmission contingency:

Question
OPA 13-1 c. Please describe the extent to which continuing discussion is planned for large customer or other customer DR resource potential.
Response
OPA 13-1 c. Through discussions, CMP learned that presently these customers can do very little to interrupt demand to respond to transmission contingencies. As a result, CMP presently does not have plans to continue discussions with these customers.

However, demand response resources can be used not only in response to a contingency, but also in a "posturing" mode[16]. CMP did not respond directly to OPA's question on the extent to which they have considered such posturing.

Question

[14] For example, the attachment to the response to OPA 13-1 indicates that three of CMP's major industrial load customers would all be willing to work with CMP in considering load and on-site generation pattern changes during times of system stress. Any such contracts could supplement and complement the terms of contracts that may already exist as part of DR resource participation in the ISO NE FCM.

[15] The non-confidential portion of the response is included as Attachment 2 to this testimony.

[16] Posturing is the dispatch of demand response resources prior to any particular contingency event, for the purpose of lowering the peak load during critical hourly intervals (e.g., between 2-8 PM on a peak summer day). This may be done in response to "emergency" conditions such as an OP-4 situation in New England, or a capacity emergency situation in PJM. However, there is no technical reason that such resources couldn't be postured even in the absence of an ISO-wide emergency or capacity shortage, if reliability needs dictate such a posturing. Another form of posturing for reliability purposes includes activation of those DR resources capable of providing load reduction in the interval subsequent to a contingency (but before the advent of an n-1-1 event).

OPA 13-1 f. Has CMP considered or analyzed the potential for DR resources to be "postured" (i.e.,called upon) pre-contingency during selected days during summer peak days as a means of mitigating the realization?

Response

OPA 13-1 f. CMP has considered the impact of demand response resources in its NTA analysis and found that, even with these resources in place, MPRP is needed.

Thus, even though demand response potential in Maine is potentially hundreds of MW larger than is either represented in the NTA analysis or has already cleared ISO-NE markets[17], CMP has no plans to continue discussing options to explore implementation of this resource based solely on conversations with just three customers and the determination that the DR resources at those sites could not provide suitable contingency response. Notably, CMP has also not investigated the possible use of demand response resources for reliability purposes with any other customers or customer groups beyond the large customers referenced in the response to OPA 13-1.

[redacted]

[redacted]

[17] Based on the demand response potential noted in the June 2009 FERC Staff report.
[18] Included as Attachment 3 to this testimony.

[redacted]

Q. Please summarize your observations on demand response resources, their relation to MPRP need, and how DR should be considered in CMP's transmission need modeling.

A. Demand response resources are clearly available in considerable quantity in Maine and in CMP's territory, based on 1) actual subscription in the ISO NE FCM, 2) [redacted], and 3) the potential identified across all sectors and reported in the most recent FERC Staff report that includes an estimate of Maine demand response potential. DR resources have the potential to significantly impact the need for MPRP elements because the effect of these resources, if utilized appropriately, would be to lower transmission system peak load levels by hundreds of MW below what CMP currently uses when conducting its need analyses with power flow modeling. CMP should conduct its transmission need analysis incorporating the effect of such resources, at a minimum as a sensitivity analysis. This implies, for example, that CMP should run power flow simulations using net peak loading levels far lower than the 1,800 and 2,000 MW load sensitivity analyses conducted in the fall of 2009 and presented in the December 4, 2009 rebuttal filing.

Very Limited Consideration of "Hybrid" Solutions in NTA or Transmission Need Assessment

Q. What are "hybrid solutions" to transmission grid reliability issues?

A. Hybrid solutions are those solutions that use a combination, or a hybrid, of transmission elements and non-transmission elements to resolve current or projected reliability violations. The use of additional transmission elements – such as new transmission lines, autotransformers, or upgraded conductors - increases the ability of the grid to reliably transfer power during stressed circumstances, such as during outages of power system generation or delivery components. The use of non-transmission elements – such as generation supply, demand response or energy efficiency – reduces the level of power that would otherwise need to be transferred over certain parts of the grid and thus also maintains reliability during stressed circumstances but does so without certain incremental transmission elements and with certain incremental non-transmission elements.

Q. Should CMP's transmission system design consider hybrid solutions?

Yes, absolutely. If you don't consider hybrid solutions, that implies ignoring an entire set of reliability options that might be lower cost than either a transmission-only or an NTA-only solution.

CMP conducted two sets of primary assessments of reliability alternatives: a transmission solution, and a non-transmission solution. Within each of those assessments, CMP conducted sensitivity analyses. For example, the NTA analysis looked at individual regions, and the transmission assessment looked at numerous transmission options. But with extremely limited exception[19], CMP

[19] The exception is the NTA assessment of options with different forms of VAR support. This is an important aspect of CMP/LaCapra's approach to assessing NTAs. When LaCapra included the reinforcing

never attempted to analyze options that combined the best elements of each of those sets of options.[20]

Ideally, CMP's design for reliability solutions would be least-cost, optimizing across the range of transmission and non-transmission elements available. Practically speaking, this does not mean attempting to analyze an infinite combination of transmission and non-transmission components, but rather invites a thoughtful planning assessment of just which transmission elements likely belong in a true "baseline" model - such as (for example) additional autotransformers and elimination of the root cause of severe double-circuit tower loss contingencies. It also implies that forecast peak loads would include a net lowering effect that demand response resources can provide.

CMP's power flow modeling could have been conducted on systems with such combinations of inputs. But in practice, CMP's baseline transmission assessments incorporated only the effect of energy efficiency. And CMP's NTA assessment relied upon a baseline transmission system with insupportably low threshold load levels that allowed for no initial, incremental improvements such as the new South Gorham autotransformer. Even after it became clear that the second South Gorham autotransformer would be in place, no updates to the threshold load levels were made to inform an incrementally-updated NTA analysis provided in the December 2009 LaCapra rebuttal testimony.

Q. The LaCapra Associates rebuttal testimony reiterates the assertion that the original NTA analysis included an analysis of hybrid solutions.[21] Please comment.

A. The LaCapra rebuttal testimony refers to the eighteen different combinations of reliability assessments contained in the NTA assessment as evidence of a hybrid

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effect of VAR resources in its NTA assessment, the result was a raising of threshold load levels and a reduced need for NTA supply resources (relative to the "no VAR" case).

[20] For example, CMP refers to the transmission solution as a "standalone backstop" (Exh. I-2, p 13/373), and the NTA components do not contain transmission elements other than VAR support (see, e.g., Exh. I-3, page 5/464).

[21] LaCapra rebuttal testimony at page 15.

solution assessment.[22] Those combinations included eighteen different "MPRP transmission vs. non-transmission" solution comparisons but except for limited VAR support sensitivity, they contain no "MPRP transmission vs. hybrid transmission/NTA". A true hybrid assessment would have compared the MPRP to a solution that used incremental transmission and non-transmission components. No such assessment has been performed.[23]

Three of the 18 LaCapra combinations were assessments of backbone transmission vs. NTAs, and the other fifteen of 18 were assessments of local transmission vs. NTAs. The extent of "hybrid" solution analysis was limited to comparing the NTA against transmission solution sets that contained either no VAR support, static VAR support, or else dynamic VAR support. Technically, this is an analysis of a "hybrid" solution, but the hybrid consists only of the inclusion of reactive support transmission elements. While this is an important inclusion, it is a very minimal transmission element addition to the baseline transmission system against which NTAs are then tested.

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[22] Ibid.

[23] Other assessments carried out in 2009 did not include the combination of NTA and transmission elements that make up hybrid solutions.

Q. What is the effect of limiting the inclusion of transmission elements to just reactive support components when assessing a hybrid solution?

A. The effect is to exclude from the baseline those transmission components that likely have a big "bang for the buck" quality. This includes but is not limited to components such as

- the second South Gorham autotransformer,
- the removal of the double circuit tower contingencies by eliminating the use of single towers in those instances,
- the use of another source of 345 kV supply to the Portland area from the north (Surowiec),
- consideration of use of other autotransformers, and
- consideration of at least limited use of state-of-the-art special protection systems.[24]

Each of these transmission system elements or set of elements reduces the reliability impact of different contingencies – either N-1 or N-1-1 – on the system and likely supports a higher "threshold load level" to which NTAs must then be designed. Higher threshold load levels lead to lower NTA requirements.

Q. Did the NTA Analysis, and the "threshold load level" analysis it depends upon, consider any hybrid solutions that use any transmission elements other than increased VAR support?

A. No. Even after it was acknowledged that the second South Gorham autotransformer was to be installed by 2011, any effect on the threshold load level was not updated and no subsequent changes to the NTA assessment were made.

[24] ISO NE Planning Procedure No. 5-5 "Special Protection Systems Application Guidelines" allows limited use of SPSs.

Q. Did the December 2009 rebuttal testimony contain any updates to LaCapra's original NTA analysis?

A. Yes, but those changes were limited and did not reflect any further consideration of hybrid solutions, or any change to the threshold load levels.

Q. Hasn't CMP's subsequent analyses in response to Staff, OPA and GridSolar requests addressed this?

A. No, not in a comprehensive manner that would illustrate the effects on reliability need of a combination of transmission and non-transmission elements.

The May 29, 2009 needs analysis in response to MPUC Staff requests addressed three different peak load levels – 1,600 MW, 1,800 MW, and 2,000 MW – and included other system changes, but it did not include, for example, the second South Gorham autotransformer, any other transmission system improvements, or the effect of demand response resource utilization to lower peak loads below the 1,600 MW level.

The July 2, 2009 filing carried out further examination of the three load level analyses requested by MPUC Staff and presented in the May 29, 2009 report, by adding in a set of transmission system improvements. However, it did not run the analyses to incorporate the effect of significant demand response resources, either those already cleared in the FCM, or those that qualified as a resource but did not clear the FCM. Notably, this analysis did illustrate that at lower load levels – 1,600 MW peak – and with a significant increment of transmission improvement[25], reliability violations were much lower than that resulting from the initial CMP needs assessment.

CMP then addressed requests by GridSolar and the OPA, and filed a report on September 1, 2009. These analyses also did not include the effect that demand response resources would have on reducing peak load levels, nor did they attempt to incorporate any other NTA resources beyond energy efficiency. It did include

[25] See page 1 of the July 2, 2009 filing for a list of the seven major categories of improvements considered.

the effect of the second South Gorham autotransformer, and load power factor correction to 0.975, but no other transmission improvements were included.

Lastly, the December 4, 2009 filing included load sensitivity analyses of MPRP, but did not include the effect of demand response resources or other NTAs besides inclusion of the second South Gorham autotransformer.

Q. What do you conclude from your examination of hybrid solution issues?

A. Despite the significant efforts of CMP to model various alternative scenarios, there has yet to be a comprehensive transmission need analysis – e.g., utilizing the output of a set of power flow runs - after first accounting for all demand-side resources and including selected lower cost and "highly impacting" transmission elements such as the second South Gorham autotransformer, load power factor correction, and elimination of double circuit tower contingencies.

It is axiomatic that increasing peak load levels incorporated into the transmission power flow model will show increasing levels of reliability violations, but this does not prove that such increased load levels will "show up" on the grid if other opportunities – e.g., cost-effective demand response – are aggressively pursued. Incrementally including lower cost/highly impactful transmission elements into the models can be highly revealing of subsequent incremental transmission need, especially when first including the effect of demand response resources to lower peak loads during stressed times.

FCM Issues - Capacity Price Separation and NTA Modeling

Q. What is "capacity price separation" in the ISO NE Forward Capacity Market (FCM)?

A. All load in New England, including Maine load, is required to meet capacity obligations to ensure resource adequacy. These obligations can be met either by 1) self-supplying qualified capacity, or 2) buying capacity through the ISO NE forward capacity market auctions that take place annually.[26] These auctions set prices for capacity resources required for reliability reasons, for those that don't self-supply. These auctions result in capacity sales and purchase commitments for one year, and that commitment is for a period three years out on the horizon (i.e., the fall 2009 FCM auction commits sellers and purchasers to prices and quantities for the 2012/13 period[27]).

In a manner somewhat analogous to locational marginal pricing (LMP) for energy, the capacity prices set at auction are also locational, with different prices possible in different zones, if transmission constraints between zones are binding. This construct is intentional - regions with surplus capacity can have lower prices, and regions short on capacity can have higher prices.

For the current FCM construct, there are two zones – Maine, and the rest of New England. Maine is considered an "export zone" because the potential for binding constraints is in the exporting direction. In previous auctions, and possibly for future auctions, there could be more than just two zones. For example, the Boston region could be its own zone with separate capacity prices, as could load pockets in Connecticut. Generally, transmission reinforcements into such zones increase transfer capacity and can eliminate binding constraints, which would lead to equal prices across zones.[28] For the first three ISO NE FCM auctions there was no price separation. An artificial "price floor" was in place, which potentially prevented the separation of prices in the auction.

Q. Why is this relevant and important to the MPRP case?

A. FCM auction price separation is relevant and important because it greatly influences the prices that Maine load may pay to meet its capacity obligation. Capacity costs can represent a substantial fraction of the overall costs to

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[26] Additional "incremental capacity" auctions occur in addition to the main auction.
[27] Resources can elect to seek 3-year or 5-year commitment terms.
[28] This is directly analogous to an energy market dispatch period where there is no congestion component.

consumers of delivered energy[29]. The non-transmission alternative in Maine relies heavily upon new generation supply to ensure reliable grid operation, and this new supply affects the market dynamics of the FCM auction. This market dynamic in turn significantly affects the overall costs of non-transmission solutions as alternatives to the MPRP.

Q. Sections D and E of the LaCapra rebuttal testimony address ISO NE Forward Capacity Market issues, including price separation, FCM revenue and related self-supply issues. Please comment.

A. The LaCapra rebuttal testimony states that "Fagan's Assumptions Regarding FCM Price Separation Are Inappropriate."[30] On the contrary, the assumption of future FCM price separation between Maine and the rest of the New England pool is not only appropriate but would be a logical market outcome, given the structure of the FCM and the inherent attributes of a reliability solution using a Maine NTA approach. The structure of the FCM is such that the likelihood of price separation increases if an export zone has surplus generation. The inherent attribute of the NTA approach is that surplus generation results.

Q. Even if prices do separate in future FCM auctions, will the separation lead to NTA solutions that are cheaper than an MPRP solution?

A. Possibly. LaCapra demonstrates[31] that a 38% price separation in its original NTA analysis leads to equivalent outcomes between NTA and stand-alone MPRP transmission solutions. However, much of underlying premise of the original NTA assessment has changed. Load forecasts, demand response potential, and projected patterns of FCM price levels have all changed. As I indicated in my direct testimony, threshold load levels should also be re-analyzed to at least account for actual changes such as the installation of the second South Gorham autotransformer. Threshold load level increases lead to lower NTA supply

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[29] In the initial NTA assessment, capacity costs were on the order of 15-17% of total Maine "societal" costs as defined by CMP/LaCapra.
[30] LaCapra rebuttal, Section D heading, page 21.
[31] LaCapra rebuttal, pages 23-24, "Price Separation Break-Even Analysis".

resource needs. Threshold load levels should also be increased to account for other low cost/high impact transmission elements prior to determining the level of NTA supply that is necessary. All of these changes would need to be made to the NTA assessment before the "equalizing" level of price separation could be determined.

Q. LaCapra discusses my direct testimony on how self-supply of FCM obligations and price separation leads to NTA approaches being less expensive than MPRP. Please comment.

A. At page 21, LaCapra states

> "According to that theory, the lower capacity prices in the NTA scenario, which is paid by load serving entities and paid to capacity resources, would reduce the NPV of the costs of the NTAs without changing the NPV of the costs for the MPRP."

In the NTA assessment model it is not the "cost of the NTAs" that is most relevant for the cost comparison, but rather the "FCM costs", especially in comparison to the "FCM costs" that occur in the MPRP scenario.

First, as LaCapra acknowledges, self-supply using new NTA resources lowers the cost differential between the NTA scenario and the MPRP scenario (see Table 3 below). Table 3 (last column, OPA scenario 1 – Self-Supply) shows NTA scenario costs of $11,778 million (NPV) when self-supply is used, compared to LaCapra's computation of $12,070 million (NPV), because the self-supply scenario essentially allows 100% of NTA generation to obtain FCM market revenues. LaCapra's value of $12,070 million assumes that only 50% of NTA generation receives FCM revenues.

Second, with price separation, the cost differential can be eliminated, depending of course on the extent of price separation and other underlying parameters. Using LaCapra's original model, this is clearly seen. LaCapra corrects my inadvertent reduction in OATT costs[32] and provides a revision to my original Table 9 (Fagan direct testimony, page 28) that illustrates self-supply effects and price separation effects when comparing MPRP with an NTA solution and using all of the other original NTA model inputs:

[32] In my direct testimony, I changed inputs to LaCapra's NTA Excel model to show the effect of a more consistent FCM market representation in the case of an NTA solution. I inadvertently reduced the OATT obligation in the NTA case (as if NTA generation were all behind-the-meter).

Table 3. LaCapra Revision to Fagan Original Table - Correcting OATT component and Illustrating Effect of Self-Supply and Price Separation

NPV SOCIETAL COSTS

NPV 2008$ in millions	TS_EE	NTA per OPA filing	Corrected OPA NTA
CMP Original	11,653	12,070	n/a
OPA Scenario 1 – Self Supply	11,650	11,593	11,778
OPA scenario 2 – Self Supply with Price Separation	11,650	11,317	11,502

Source: LaCapra Rebuttal, page 19. Original: Fagan direct, Table 9, page 28.

As this table shows, the effects of self-supply and price separation make the NTA solution outlined by LaCapra less expensive than MPRP (on a Maine societal cost basis[33]) under the price separation assumption illustrated in Figure 1 of my direct testimony.

Since that time, as LaCapra describes, the market environment has changed and FCM prices are projected to be lower.

LaCapra's update of the NTA assessment includes changing the FCM price projection and adding a sensitivity assessment under a full self-supply scenario. This is shown in their table on page 29. They further update the NTA analysis in an isolated manner by adjusting required generation supply to lower load forecast requirements (table on page 23). However, neither of these adjustments addresses the potential for price separation.

Q. Please discuss the Maximum Capacity Limit ("MCL"), Maine export capacity, and its effect on FCM revenues and NTA generation.

A. LaCapra states at pages 25-26

"…Maine's existing transmission system …could not support the participation of all required NTAs to displace the MPRP in the FCAs." (page 25)

And

> "Under this scenario, new capacity such as the NTA resources might not be able to clear in subsequent FCAs in later years." (page 26)

These two statements seem to suggest that NTA's require increased Maine export capacity in order to participate and/or clear in the FCM auctions. However, regardless of the level of export capacity from Maine to the rest of New England, NTA and other resources can participate in the FCM auction if they are deliverable to the Maine capacity zone. In an auction with a floor price, the effect is that "surplus generation" clears in the auction, and prices or quantities are prorated down. Without a floor price, competition drives the Maine zone auction price downward until the auction clears with no surplus but with a lower price than the rest of New England. The end result is the same for the NTA approach – lower capacity prices in Maine relative to the rest of New England.

Also, LaCapra states in footnote 19:

> "As we discussed above, there were a number of projects in Maine that were not qualified for FCA2 and FCA3 due to limitations of the transmission system"

Footnote 19 is referencing a discussion concerning Maine's "export capacity". However, the reason that projects that did not qualify for FCA2 and FCA3 had nothing to do with Maine's export capacity – it had to do with intra-Maine constraints.[34] These projects could qualify and clear in an FCM auction even if there is no increase in Maine export capacity; they just need to be deliverable to the Maine capacity zone. There currently exist three wind plants in Western Maine that have cleared the FCM and are deliverable to the Maine capacity zone. The wind plants that did not qualify for acceptance as a Maine zone resource are north of the Orrington South interface (and one Western Maine resource). A more careful assessment of the reasons for their rejection as a qualified capacity resource is required to determine the extent of transmission reinforcement that would be needed for qualification.

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[33] Maine societal cost is essentially the net present value of the costs Maine consumers pay for delivered energy, and it reflects the fact that Mainers would pay only a share of MPRP costs. See Exhibit I-3, NTA Assessment, page 5/464, and pages 49-50/464.

[34] See table on page 9 of LaCapra rebuttal.

Planning Reserve Margin – Maine

Q. LaCapra states that "micro" systems require higher installed reserve levels.[35] Please comment.

A. My direct testimony included the observation that the actual reserve margin[36] in the *entire state* in 2012 under LaCapra's NTA Assessment would be 69%, and that this was excessive. While LaCapra's rebuttal testimony uses a 1,000 MW hypothetical load pocket example to make a point, LaCapra's direct testimony on the actual NTA need (69% planning reserve margin) for the entire state (unless MPRP is built) is the issue at hand.

LaCapra's hypothetical load pocket example presented in their rebuttal testimony is academic to the issue and serves to illustrate load pocket reliability issues, but it does not address my original testimony that LaCapra's use of a 69% planning reserve *for the entire state of Maine* is excessive. I stand by my original testimony.

LaCapra uses a hypothetical example to illustrate that a 55% reserve margin might be required to reliably support a 1,000 MW load pocket with insufficient transmission. This may indeed be the case, although operational actions taken between the n-1 event and the n-1-1 event in the example given could lead to requirements significantly lower than a 55% reserve margin; the example does not address this detail[37]. Also, a 55% reserve margin itself is significantly lower than a 69% reserve margin (a 55% reserve margin for a base 2,360 MW load equates

[35] LaCapra rebuttal, p 16-18.

[36] Reserve margin is the amount of supply resource capacity over and above what is needed to meet peak load. On a percentage basis, it is equal to the excess capacity above peak load, divided by the peak load level.

[37] For example, only 300 MW of new supply (instead of 400 MW) might be required in lieu of increased transmission import capability if 50 MW of quick-response demand response were in place. This would equate to a load pocket reserve margin of 45%, significantly lower than 69%. Other steps could lower this further. This illustrates that even within a load pocket, there are ways to reduce a required margin well below the 69% that LaCapra has determined is required for the entire state.

to 3,658 MW of supply; a 69% reserve margin equates to 4,000 MW of supply); LaCapra required[38] 69% for the entire state.

Reinforcement of transmission into load pockets can be a reasonable and an economical means of ensuring reliability. However, MPRP in its entirety is much more than reinforcement of transmission import capacity into load pockets. In LaCapra's example, reinforcement of transmission is considered with a 400 MW "third line" into the load pocket. This allows for the planning reserve to remain at 15% in LaCapra's load pocket example. This is somewhat akin to adding the second South Gorham autotransformer, or the autotransformer and another 345 kV line into the Portland area, and such actions – whether in the hypothetical example or in reality as with the second autotransformer installation - can be reasonable. However, the thrust of MPRP goes well beyond just the second South Gorham autotransformer installation.

The NTA analysis, because it excluded hybrid alternatives, did not assess situations where incremental transmission first installed (for example, to bolster lock pocket deficiencies) results in a lower need for resulting non-transmission alternatives. The example in LaCapra's rebuttal testimony illustrates this – a much lower level of overall statewide NTA generation is required if the load pocket is first reinforced.

Wind Resources and MPRP

Q. CMP's December 4, 2009 filings reference the ability of MPRP to better accommodate integration of renewable resources. Conservation Law Foundation's (CLF) November 3, 2009 filing also addresses Maine wind issues. Please comment.

A. Volume IV-A, the rebuttal testimony of Mr. Conroy and Mr. Conant, addresses wind integration issues.[39] A portion of the LaCapra rebuttal testimony addresses

[38] With a revised load forecast, and a downward revision to the NTA requirement in 2012 to 600 MW (from 800 MW), LaCapra's required planning reserve margin in 2012 for the entire state under an NTA

the difference between Staff scenarios and the MPRP with respect to renewable development in Maine.[40] CLF-sponsored testimony of Mr. Tilghman addresses wind development in Maine.

Q. Do these testimonies comprehensively address transmission needs for wind development in Maine?

A. No. These testimonies do not comprehensively or sufficiently address fundamental issues of extent, location and timing of transmission reinforcement needed for wind development and the resulting wind energy delivery to the grid pursuant to Maine policy goals. This is understandable, since MPRP was proposed as a reliability solution and not a wind resource transmission plan.

Mr. Conroy and Mr. Conant's testimony and Mr. Tilghman's testimony generally use the MPRP thermal transfer capability increases of key Maine interfaces as a point of departure to describe in general how increased transmission infrastructure reflected in the MPRP proposal supports development of Maine wind.[41] However, in the absence of a comprehensive analysis it would be a mistake to assume that construction of the MPRP, in its entirety and at this point in time, is the most reasonable approach to transmission build-out to support Maine's wind development goals.

Q. What is necessary for wind resource interconnection and integration in Maine?

Utility-scale wind resources in Maine generally need to interconnect to the 115 kV grid, and the 115 kV grid needs to support the injection of such new wind under varying conditions of resource output, load, and other generation use of the grid. Both non-MPRP elements and some MPRP elements might be necessary to support wind interconnection.[42] For example, ensuring that the underlying 115 kV

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scenario is even higher – roughly 80%.

[39] Conroy and Conant Rebuttal testimony, pages 31-40.

[40] LaCapra rebuttal, pages 7-12.

[41] Conroy and Conant Rebuttal, page 32:7-8; Mr. Tilghman Direct, 17:16 to 18:11.

[42] As an example, the 115 kV transmission project between Wyman Hydro and Heywood Rd. (i.e., the new Section 241) supports wind development but is not part of MPRP.

systems in Western Maine and in the Waterville/Winslow/Skowhegan region are capable of supporting planned wind resource interconnection is a logical step. However, it is an unproven assertion that increases in the firm transfer capability of all three major interfaces - Maine-NH, Surowiec South, and Orrington South - are required to enable such interconnection and integration.

In some instances reinforcement may be required to improve the 115 kV system interconnections to the 345 kV grid, but an economic assessment that includes production cost modeling effects should be conducted in addition to power flow modeling that tests only for reliability violations. This will inform the economic tradeoff of the cost of incremental transmission vs. any lost value that may be associated with congestion or required curtailment of resources in the absence of any particular proposed transmission improvement.

It is not at all clear that increases in the thermal transfer capability of the major Maine interfaces is also required (in addition to certain 115 kV reinforcement), at this time, to support significant increments of installed wind in Maine.

Q. Does CMP or CLF's testimony address specific reinforcement needs for wind resources?

A. CMP's testimony does address this; CLF's testimony does not. CMP's testimony helpfully includes reference to instances of 115 kV reinforcement (and the Surowiec-Raven Farm 345/115 kV reinforcement) that specifically help to integrate wind resources[43]. However, it does not sufficiently address why the more extensive 345 kV transmission increases associated with MPRP – and in particular increased transfer levels across each of the major interfaces - are required to integrate Maine wind onto the grid. A more comprehensive "wind and transmission" analysis is required – and should be undertaken – to assess this.

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[43] Conroy and Conant, 35:3 through 36:9 (Western Maine); 38: 1-8 (Offshore wind, western Penobscot Bay, and eastern Casco Bay).

For example, CMP's claim that the Orrington South interface reinforcement enables additional interconnection in Aroostook county and downeast Maine[44] does not address the fact that some portion of the over 700 MW of thermal generation north of Orrington South (e.g., MIS and Bucksport G4) is exactly what wind resource output might displace during on-peak periods (to the extent wind is available at those times and those units are otherwise economically dispatched on). During off-peak periods, those fossil generation units may not be running for economic reasons[45], thus making available significant amounts of the existing transmission system to support energy delivery from new northern wind.

The testimony does not sufficiently address the primarily economic issue associated with congestion concerns and the manner in which wind will offset thermal generation in Maine, other than giving a brief reference to this issue[46]. For example, there has been no assessment of congestion impacts on the existing system, or any particular reinforced system (such as one with Section 241 in place) associated with wind resource development in Western Maine and the Waterville/Winslow/Skowhegan region.

Q. Will Maine wind development, operation and integration require increased thermal capacity of all of the major transmission interfaces in Maine?

A. Not necessarily. I do not know exactly what wind developers in the future will require in order to finance, plan and construct projects in Maine. However, I do know that existing and planned wind projects have proceeded without obtaining ISO NE capacity market revenues, and have proceeded without any certainty that MPRP will be built. This evidence validates a fundamental premise associated with wind resources: their value lies primarily in energy provision, not capacity

[44] Conroy and Conant Rebuttal, 38: 9-23.
[45] How frequently these units might be normally dispatched off for economic reasons during off-peak periods is exactly the type of analysis that is required to determine the economic importance of increasing the Orrington south interface capacity in order to support delivery of more wind energy.
[46] Conroy and Conant, 38: 16-20, "Without more transfer capability, … there will likely be increased congestion as more renewable resources are developed. Without more transfer capability across each interface, wind will just merely offset thermal generation in Maine."

provision or reliability support. As LaCapra's table[47] illustrates, wind resources that were rejected from the FCM market nonetheless are either up and running, or are continuing to proceed to the development stage. Notably, the Rollins wind farm announced a 20-year contract approval from the Maine PUC[48] even though it failed to be included as a capacity resource in both the FCM 2 and FCM 3 auctions. It is my understanding that long-term contracts for the output of a wind resource are one of the most important elements required to secure wind development. The Rollins wind farm appears to illustrate the greater importance of that factor for development, as compared to FCM participation and bulk transmission upgrades beyond that required to interconnect.

Q. What effect on wind development would result from improvements to the thermal transfer capacity of the Surowiec South and the Orrington South interfaces, but little or no increase to the ME-NH interface transfer capacity?

A. In that instance, it would be more likely that Maine wind projects would be qualified to participate as a Maine zone capacity resource[49], and would obtain FCM capacity revenues based on the Maine zone FCM prices. Maine wind projects do not have to "reach" the rest of New England FCM capacity zone in order to participate as FCM capacity resources. As I have noted, wind resources have been planned, financed and built in Maine without *any* participation in the ISO NE FCM market, and three Maine wind farms are certified as capacity resources. And as long as a Maine wind resource is able to interconnect to the Maine grid, it has full access to the ISO NE energy market – and like other Maine resources, is subject to locational energy pricing impacts if the revenue stream from its energy output is tied to ISO NE locational energy prices.[50] It is certainly not clear that increases to the ME-NH interface capability are required to support

[47] LaCapra rebuttal, page 9.
[48] MPUC press release, October 8, 2009. Available at http://www.maine.gov/tools/whatsnew/index.php?topic=puc-pressreleases&id=80515&v=article08.
[49] Notably, some existing wind resources in Maine – Kibby, Longfellow, and Record Hill – are already Maine zone capacity resources. All but one of the wind resources rejected from the FCM2 and FCM3 auctions are located north of the Orrington South constraint.
[50] It is not required that Maine wind farm output purchase price be tied to ISO NE energy market prices.

wind development in Maine. Absent MPRP, there likely remains considerable "energy headroom"[51] across that interface, and the other Maine interfaces.

Q. How much "energy headroom" currently exists on the ME-NH interface?

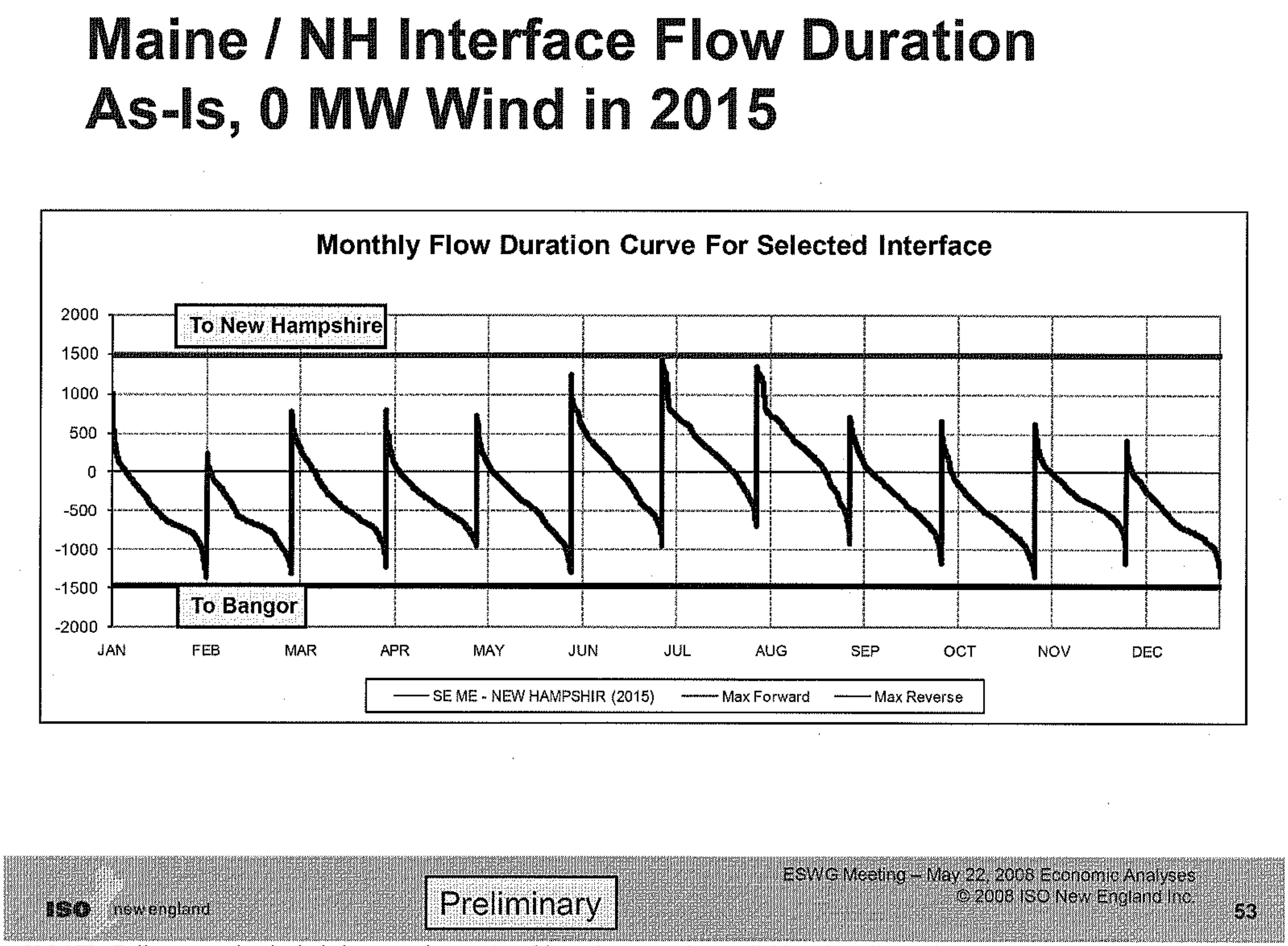
A. There has been no examination in this case of the amount of "energy headroom" that currently exists or is projected to exist across the ME-NH interface, or for that matter any of the internal Maine interfaces. However, for the Maine Power Connection (MPC) case, ISO NE conducted preliminary analyses that roughly identified ME-NH interface headroom in 2015, given the conditions modeled.[52] Figure 3 below provides that indication. The area above the monthly flow duration curves and below the ME-NH interface limit ("To New Hampshire", at the top portion of the graph, at the 1,500 MW level) is roughly the amount of headroom that exists, based on the conditions modeled in that scenario.

As seen in the graph, during winter months flow is south-to-north in most hours, leaving more than the full interface capability for Maine wind resources to flow north-to-south across the interface during this season[53]. During the shoulder seasons, the flow duration is also mostly south to north. Only during the summer period – when Maine wind output would expect to be at its lowest level of the year anyway - does the flow across the interface reach towards the maximum

[51] Energy headroom is essentially a term for how much increased energy flow – i.e., MW * hours - across the interface would be possible before the interface would become binding during economic dispatch.
[52] The presentation cited here also includes monthly flow duration curves for the Maine internal interfaces.
[53] Actual flow quantity and direction across the interface results from the interaction of all generation and load patterns on the New England and regional system; obviously Maine wind output cannot be physically directed to flow south into NH. To the extent that incremental wind in Maine displaces equivalent Maine fossil generation, or NB-to-ME imports, flow across the ME-NH interface would not change. If the displaced generation was located in southern New England, flows would increase across the interface.

level of 1,500 MW, leaving less room for incremental wind to displace southern NE resources, in that season.

Figure 3. ME-NH Flow Duration Slide from ISO NE Preliminary Analysis for the MPC Case



Source: ISO NE. Full presentation included as Attachment 4 to this testimony. Also available at http://www.iso-ne.com/committees/comm_wkgrps/othr/econ_stdy/mtrls/2008/may222008/mpc_economic_analysis_preliminary_5_22_2008.pdf.

Q. Please summarize what this graph illustrates.

A. This graph illustrates that even if Maine wind did not displace other Maine or NB generation resources, considerable room still exists to "deliver" much of Maine's intended wind energy to the New England regional market in the absence of increased transfer capability across the ME-NH interface.

Q. Do you have additional comments on Mr. Tilghman's testimony?

A. Yes. I have addressed one major concern that Mr. Tilgman makes[54] in my testimony above, regarding the undocumented assertions that increased thermal transfer capability of the major internal interfaces is required to promote wind development and integration in Maine.

In addition, Mr. Tilghman makes unsupported statements concerning spatial and temporal diversity of the Maine wind resource, and such diversity's effect on the coincident output of aggregate Maine wind generation, and the aggregate wind resource output coincidence with low local demand. I first refer to the following two statements:

> "Rather, I expect Maine's wind fleet would be at 100% (or ramping up or down from that number) for 1/3 of the hours in the year. Furthermore, I would anticipate that Maine's onshore wind projects will tend to produce energy at more or less the same time" (Tilghman Direct, at 23: 9-13)

> "While there may be some geographic diversity of output across Maine's onshore wind fleet, output of the wind projects in Maine is likely to be highly correlated – which is to say that projects are more likely to be generating and idle at the same time." (Tilghman Direct, at 24: 9-12)

Spatial diversity refers to the effect on coincident aggregate electrical output of wind farms that are located many miles from each other and do not see identical wind levels at the same time. It can also refer to the spatial effect on aggregate output of all turbines at a single wind farm. Temporal diversity refers to the fact

[54] For example, Tilghman testimony at pages 17:16 through 18:11.

that wind levels change over time. The combination of these effects lowers both the aggregate level of coincident wind output (compared to the sum of total nameplate capacity) from all wind resources "upstream" of a particular Maine interface and lowers the aggregate temporal variability of output. Both of these are important to grid operations.

Mr. Tilghman also states,

> "In what may be the wind developer's worst case scenario, the combination of low load demand and high generation output could create an over-generation condition on the grid, causing the grid operator to require generators to reduce output. When a wind generator is forced to curtail output for reliability reasons, the project owner will lose…[revenues]." (Tilghman Direct, at 20: 3-10)

Q. Are these statements supported with any data or report references on the spatial and temporal diversity of wind resource output across the state of Maine?

A. No.

Q. What effect would actual wind resource diversity have on determining transmission grid loading and expected congestion levels in Maine?

A.. The effect of increasing diversity of output across wind farms in Maine regions would be to reduce 345 kV bulk system grid loading (relative to the "no diversity" case where all wind is on at full output at the same time during windy periods). The effect would be greatest on the furthest "downstream" interface, the ME-NH interface, because that interface would "see" all the Maine wind in aggregate, at its coincident level. The effect of grid loading on the ME-NH interface would include any diversity existing between the Western Maine and the downeast Maine regions, for example.

Q. Has Mr. Tilghman explained or investigated these effects for Maine?

A. No.

Q. Does Mr. Tilghman address how economic dispatch affects which generation would first be turned down during "low load" and "high [wind] generation output" conditions?

A. No. Nor does he acknowledge that during such low load conditions, the transmission system is likely to be able to absorb considerable amounts of wind, if available, because fossil generation is likely to be offline or operating at low levels, for economic reasons.

Q. Are there general observations available on wind resource diversity phenomena and how it can impact transmission planning?

A. Yes. The following paragraphs are from the recently released (January 2010) Eastern Wind Integration and Transmission Study (EWITS)[55] prepared for the National Renewable Energy Laboratory (NREL) and address, at a high level, the issues I am referring to:

> Because it is primarily a source of energy, not capacity, wind generation does not fit well into conventional resource adequacy-based transmission planning processes. In conventional planning, the focus will typically be concentrated on certain system conditions—peak or minimum load hours, or operation of the system with a major facility out of service. The status of conventional generating units during these periods is usually a given. With large amounts of wind generation, the disposition of other conventional generating units may not be so easily ascertained; in addition, high amounts of wind generation are likely in off-peak hours or seasons that might not be of special interest for reliability issues. (EWITS Study, page 98)

And,

> "Based on the work done in this study, the EWITS team can make a number of general observations. **The wind generation does not need 100% transmission for the rated wind generation connected to the transmission system**. The geographic diversity of wind generation produces a coincident peak capacity of 80%–90% of the total rated wind generation. **Transmission does not need to be sized to handle all the wind generation at its maximum coincident output. Some wind can be curtailed for some hours more economically than building**

[55] Available at http://www.nrel.gov/wind/systemsintegration/pdfs/2010/ewits_final_report.pdf.

> **transmission that would be loaded only for those few hours. Adding more generation with small curtailments to meet the renewable energy standards can be more cost-effective than designing a transmission system for the peak coincident output of the generation.** The top-down economic process used for EWITS determines the curtailment energy for wind and also the potential benefit of adding transmission compared to the cost." (EWITS Study, page 212) (**emphasis added**)

I note that in this case, importantly, there exists considerable fossil generation that is also using the same transmission system; curtailment that might be required "for some hours" on the Maine system is not automatically for a wind resource, and in fact would more likely be a fossil resource, to the extent such a resource is not needed for reliability reasons.

Q. Please summarize your observations concerning wind development in Maine and the need for the entire MPRP.

A. There is no doubt that a reinforced transmission grid in Maine will increase the means to deliver more firm capacity relative to the existing grid. However, there is no analysis in the record of the specific need to increase the firm capacity of the major bulk power transfer paths in order to interconnect and operate wind resources whose value is primarily energy-based. Maine has well over 2,000 MW of fossil-fired generation capacity with energy output that generally would be displaced by wind resources during economic dispatch – essentially freeing up transmission.

CMP has emphasized the importance of increasing transfer capability across the Maine interfaces yet has produced no analysis that demonstrates the outcome of economic dispatch associated with increases in Maine wind resources. There has been no assessment of the changes to congestion levels in Maine and New England – instead, there has been an undocumented assertion that without MPRP, wind resources may not develop – even though the reality is that they have already been developing.

There is neither reliability nor economic requirements to have a transmission system in Maine that can accommodate the full installed capacity of both the existing fossil-fuel-dominated resource base and increases in installed wind capacity of up to thousands of MW. For reliability, the system needs to meet peak load needs – in this instance, peak loads after accounting for the ability of demand response and energy efficiency resources to lower such peaks (and possibly the use of solar PV to also contribute to such reduction). From an economic perspective, the economic dispatch construct in which the region's electricity market operates leads to wind resources displacing higher-marginal cost resources – Maine's gas- fired resources, for example - in most hours.

One last observation I make is that because of economic-based marginal dispatch of energy in New England, the increase in interface transfer capability that would accompany a full MPRP would lead to - on the margin - the increased use of fossil-fuel resources to produce and deliver energy to the grid, since wind resources would generally be dispatched ahead of fossil resources.

Observations on Grid Solar Proposal

Q. GridSolar LLC has submitted multiple filings in this docket.[56] Please comment on the GridSolar proposal.

A. The GridSolar proposal is a form of non-transmission alternative to meet the reliability needs of Maine. Its fundamental premise is to lower peak load levels on the Maine grid through timely, as-needed installation of distributed solar PV. As proposed, the resulting peak load levels would then be low enough to eliminate the need for MPRP transmission reinforcement to meet reliability needs. The "avoided cost" associated with this eliminated transmission need is credited

[56] GridSolar Petition, January 28, 2009. GridSolar Supplemental Filing, September 8, 2009. GridSolar Second Supplemental Filing, October 27, 2009.

as a benefit for the GridSolar proposal.[57] The costs of avoided sub-transmission and distribution system upgrades are also included as a proposal benefit.[58]

The proposal includes the provision of back-up generation and demand response resources to ensure lower net peak system load levels during periods when the solar PV resource output would be insufficient. It simultaneously would provide distributed energy (MWh) for end-use consumption and it would effectively displace fossil fuel consumption (net of any fossil fuel required for the backup supply resources to operate if/as called upon). Conceptually and technically, it is a fundamentally sound proposal. The overall economic feasibility of the proposal depends upon the assumptions used for the key factors of the proposal.

Q. What are the key factors that would help to determine the economic feasibility of the proposal?

A. The economic feasibility of the GridSolar proposal as an MPRP reliability substitute depends on a number of key variables, including in particular the following:

1. The temporal pattern and quantity of solar PV buildout required as part of the proposal to maintain reliability;

2. The level of avoided cost credit given for transmission, sub-transmission and distribution system savings;

3. The actual installed cost of the modules, in particular the specific effect of projected declining per unit cost trends; and, in a related manner, the extent of capture of economies of scale to achieve relatively lower per unit costs than might otherwise occur;

[57] GridSolar states that this is computed as a "residual" to determine the level of such benefit required, when combined with other revenues an after-tax return to equity of 9% is achieved. Second Supplemental Filing, page 21.

[58] GridSolar Second Supplemental Filing, page 22. It is not clear that this benefit is fully incorporated into the "cash flow" worksheet that forms a core part of the model's computation of internal rate of return on equity. The model indicates inclusion of only the transmission avoided cost. On a separate worksheet outlining MPRP rate affects, the "local reliability" adder referenced at page 22 is included.

4. The level of energy revenues, capacity credit revenues, and REC revenues available from the solar PV and backup resources;
5. Financing and investment assumptions, including the treatment of the federal ITC; and
6. The impact on Maine of macroeconomic effects from a solar PV resource policy direction.

Q. Please identify the main elements critiqued in LaCapra's rebuttal testimony.

A. LaCapra Associates indicated a number of concerns with some of the inputs used in the modeling[59], namely:

- DC to AC conversion losses; and the effective annual capacity factor which is stated as MWh/year output per MW_{DC} of installed solar PV resource.
- Capital costs ($/installed watt, DC) for the solar PV.
- The level of claimed capacity for which the solar PV resource can secure FCM payment through the ISO-NE capacity market.
- The price of renewable energy credits and energy that would apply to the solar PV output.
- Financing parameters, including especially the effect of federal Investment Tax Credit (ITC) rules[60]; and
- The value of an avoided transmission credit.

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[59] LaCapra rebuttal, pages 34-44.

[60] LaCapra states that the 30% cash grant provision, arising from the 2009 ARRA, is only available if the resource begins construction by the end of 2010. This is correct; however, the solar technology itself need not be placed in service until 2017. Based on this provision, it is possible that the 30% cash grant could be taken if the GridSolar program commences construction in 2010, for solar PV installed in later years. This is an important sensitivity in the financial model and would need to be investigated more thoroughly to determine if PV resources installed in later years, but "commencing" with a formal 2010 program can access the cash grant.

Q. Did LaCapra address job creation or local reliability benefits as noted by GridSolar in its proposal[61]?

A. No. LaCapra did not comment on the jobs creation aspect of the GridSolar proposal, nor did they comment on GridSolar's inclusion of "local reliability" investments.[62]

Q. What was the key result of LaCapra's analysis of the GridSolar proposal?

A. LaCapra used revised input assumptions in a number of areas to illustrate - through use of the GridSolar spreadsheet model - that economic feasibility is significantly affected by changes to these model inputs, to the extent that LaCapra states that the proposal is "Highly Uneconomic and Not Financeable."[63]

Q. Is the GridSolar Proposal "Highly Uneconomic and Not Financeable"?

A. No. Testing the model with a range of not unreasonable assumptions leads me to the opinion that on its face, the proposal is much more economical than one might first think. Solar PV is often labeled as a very expensive resource because per unit costs (and related levelized costs) of energy production have been relatively high, on the order of 8-12 cents/watt installed.[64] However, the prospect of a very real avoided transmission cost credit, along with potential avoided distribution/sub-transmission avoided costs, renewable energy credits, federal tax provision effects and declining cost trends all lead to much more positive financial results. Also, macroeconomic effects – installation jobs and potentially manufacturing jobs – should be considered when assessing a possible solar PV policy for Maine.

Absent any form of transmission, sub-transmission and distribution avoided cost credit; and absent the projected declining cost trends for solar PV, it might be

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[61] GridSolar, Second Supplemental filing, page 22; and page 39: 21-23; and in the financial model.
[62] GridSolar, Second Supplemental filing, page 23.
[63] LaCapra rebuttal, Section H.2 heading at page 46.
[64] See, e.g., Lawrence Berkeley National Laboratory, "Tracking the Sun II – The Installed Costs of Photovoltaics in the US from 1998 to 2008", October 2009. Figure 4., Installed Cost Trends Over Time, page 10.

reasonable to consider the proposal "highly uneconomic", but that is not the case here.

Q. Can you illustrate a set of assumptions that leads to outcomes that are roughly economically feasible?

A. Yes. Using the GridSolar financial model and starting with the Excel spreadsheet model provided by LaCapra in response to ODR-12-32 Attachment 3 (which originated with GridSolar as its financial model), I generated a different set of internal rates of return (IRR) than LaCapra illustrated in its *pro forma* analysis.[65] To show how a not unreasonable set of assumptions could lead to a feasible economic scenario for the GridSolar proposal, I used the model with the following assumptions:

1. **Solar PV Capital Costs**. A capital cost of $4,000/kW ($2011) for total "hard costs" of installation. This is higher than the $3,665/kW used by GridSolar, and lower than LaCapra's projection of $6,820/kW. This is one of the more critical variables affecting the model output. Use of a lower value reflects two patterns: 1) declining cost trends will continue, and 2) the need for solar PV could shift out in time, allowing for increased capture of declining cost trends while ensuring reliability by using less expensive EE and DR resources as much as is possible in the early years of the proposal. Current solar PV costs (i.e., 2008 and 2009 installation costs per watt), such as reported in a recent LBL paper[66] remain higher than $4,000/kW, but nonetheless there is downward pressure on prices[67] and the US DOE "targets" solar PV costs[68] to be at this order of magnitude

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[65] LaCapra rebuttal, pages 47-49.

[66] See, e.g., Lawrence Berkeley National Laboratory, "Tracking the Sun II – The Installed Costs of Photovoltaics in the US from 1998 to 2008", October 2009. Figures 4 and 5, pages 10-11.

[67] For example, in the retail price reporting section of the Solarbuzz website, it states "As a guide, the industry is looking to drive module prices down to $1.50 - 2.00 per watt over the next decade, if it is to make large inroads in to the grid tied electricity market, without subsidy." The module price is currently on the order of 50-60% of the total solar PV installation cost, thus illustrating that $4.00/watt total cost is not unreasonable at some point in the near future. See http://www.solarbuzz.com/Moduleprices.htm.

[68] US DOE, Solar Energy Technologies Program, "Solar Energy Technologies Program – 2008-2012 Multi-Year Program Plan", page 21-22, available at

(i.e., $4,000/kW) by 2010[69]. While the 2010 timeframe of this DOE target seems highly optimistic, achieving such a level over the next five years does not seem unreasonable.

2. **Solar PV REC Prices**. REC prices midway between GridSolar ($100/solar REC starting in 2011, declining to $25/solar REC by 2022) and LaCapra ($30.69 in 2011, then declining to a minimum of $15.28 in 2019, and then increasing 3%/year from 2020 forward). This reflects a balance that recognizes that even though Maine is indeed not Vermont[70], there remains uncertainty about the extent to which a regional solar REC (SREC) market may develop, or whether or not state policy in Maine may place a higher value on solar renewable energy credits than other renewable energy.

3. **Federal ITC**. Based on the provisions of ARRA 2009 that allow for a cash grant if construction commences in 2010, for solar assets installed by 2017, I presume that this financing advantage could be realized, and I toggle the model switch accordingly.

4. **Local Reliability Credit**. Distribution and sub-transmission avoided cost credit equal to an additional $6/kW-month[71] starting in 2013. This reflects a value of distribution and sub-transmission savings ("local reliability" savings) that could be seen if distributed solar resources and complementary demand response and energy efficiency resources were used.[72]

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http://search.nrel.gov/cs.html?url=http%3A//www1.eere.energy.gov/solar/pdfs/solar_program_mypp_2008-2012.pdf&charset=utf-8&qt=url%3Aeere.energy.gov/solar/+%7C%7C+multi-year+program+plan&col=eren&n=3&la=en.

[69] Ibid., page 21.

[70] LaCapra rebuttal, page 44. LaCapra noted that installations in Maine would not be eligible for Vermont solar RECS.

[71] This level is a "placeholder" value, and would change pending actual analysis of distribution system savings from the proposed GridSolar program.

[72] Note that pure "distribution" savings may not accrue if a solar PV program in Maine were limited to solely grid-connected facilities at distribution substations, upstream of much of the distribution asset. I presume that any eventual solar PV program in Maine would include installations closer to the end use, in addition to substation-located grid connected PV.

5. **Technological Improvement of Solar PV Resource**. I assumed an output level of 1,541 MWh per year per MW_{DC}, midway between LaCapra's value of 1,467 kWh per year and GridSolar's value of 1,614kWh/year. Using a value higher than LaCapra's is demonstrating the capture of technological improvements to solar PV.

6. **Capacity Credit**. While LaCapra discussed the FCM capacity credit used in the GridSolar model, it does not appear that any changes to that assumption were made in its Case 2, 3 and 4 illustrations. I have modeled the overall capacity credit for the GridSolar proposal as producing 1 MW of capacity credit for each 1 MW (DC) of installed solar capacity by changing the solar capacity credit value to 35% from 65% on the "assumptions" worksheet of the financial model.

Q. What are the results of the model when using these assumptions?

A. Table 4 below shows the "Cash Flows" worksheet from the model, illustrating the internal rates of return for 15, 20, 25 and 30 year periods.

Table 4. Results of "Cash Flow" Worksheet of GridSolar Financial Model with Alternative Input Assumptions

GridSolar, LLC - As Filed		2011	2012	2013	2014	2015	2016	2017	2018	2019
Year	0	1	2	3	4	5	6	7	8	9
Revenue										
MWH/MW		1,541	1,541	1,541	1,541	1,541	1,541	1,541	1,541	1,541
Commodity $/MWH	0.0%	[redacted]								
Commodity revenues		115,299	113,215	111,561	114,027	115,511	118,079	118,238	120,881	123,590
Capacity $/kW/mth	2.5%	*4.50*	*4.50*	*4.75*	*5.00*	*5.00*	*5.38*	*5.75*	*6.13*	*6.50*
Capacity revenues	100%	54,000	54,000	57,000	60,000	60,000	64,500	69,000	73,500	78,000
Avoided Transmission $/kW/month	N	[redacted]								
Avoided Transmission Revenues	100%	189,224	219,579	281,799	272,696	264,201	256,254	248,566	240,879	233,191
Back-up Revenues $/kW/Month	50%	*2.25*	*2.25*	*2.38*	*2.50*	*2.50*	*2.69*	*2.88*	*3.06*	*3.25*
Back-up Service Revenues		8,775	8,775	9,263	9,750	9,750	10,481	11,213	11,944	12,675
REC $/MWH	A	[redacted]								
REC Revenue		100,686	91,174	81,591	72,250	60,882	51,567	45,420	35,557	34,886
Total		467,984	486,743	541,214	528,723	510,344	500,882	492,436	482,761	482,343
Revenue per MWH		*303.71*	*315.89*	*351.24*	*343.13*	*331.20*	*325.06*	*319.58*	*313.30*	*313.03*
Expense										
Total		120,587	121,933	122,676	123,333	122,947	123,891	124,732	125,466	126,085
		78.26	*79.13*	*79.61*	*80.04*	*79.79*	*80.40*	*80.95*	*81.42*	*81.83*
Operating Income (EBITDA)		**347,397**	**364,810**	**418,538**	**405,390**	**387,397**	**376,991**	**367,704**	**357,295**	**356,257**
Interest on Debt		204,106	199,053	193,637	187,832	181,610	174,941	167,792	160,130	151,917
Tax Depreciation		733,248	1,148,133	705,589	440,063	440,063	240,918	41,773	41,773	41,773
Total Tax (benefit) cost	40%	(235,983)	(392,950)	(192,275)	(89,002)	(93,711)	(15,547)	63,255	62,157	65,027
Net Income		(589,957)	(982,376)	(480,689)	(222,505)	(234,276)	(38,868)	158,138	155,392	162,567
Income Taxes (State and Federal)		-	-	-	-	-	-	-	-	-
After Tax Income		(589,957)	(982,376)	(480,689)	(222,505)	(234,276)	(38,868)	158,138	155,392	162,567
After Tax Cash Flows										
After Tax Income		(589,957)	(982,376)	(480,689)	(222,505)	(234,276)	(38,868)	158,138	155,392	162,567
Plus Federal Production Tax Credit	100%	-	-	-	-	-	-	-	-	-
Add Back Tax Depreciation		733,248	1,148,133	705,589	440,063	440,063	240,918	41,773	41,773	41,773
Plus State Tax Credit (if any)	0%	-	-	-	-	-	-	-	-	-
Less Principal on Debt Service		70,315	75,367	80,783	86,588	92,810	99,480	106,628	114,290	122,503
Total Debt Service		274,420	274,420	274,420	274,420	274,420	274,420	274,420	274,420	274,420
DSCR (include PTC as coverage)		1.27	1.33	1.53	1.48	1.41	1.37	1.34	1.30	1.30
Debt Service - Interest Only		204,106	199,053	193,637	187,832	181,610	174,941	167,792	160,130	151,917
DSCR (include PTC as coverage)		1.70	1.83	2.16	2.16	2.13	2.15	2.19	2.23	2.35
Less funds not distributed										
Sinking fund for major overhaul		-	-	-	-	-	-	-	-	-
Federal ITC Grant (Y or N)	Y	1,220,250								
Total AT Cash Flow for Distribution	(1,961,188)	1,293,227	90,390	144,118	130,970	112,976	102,570	93,284	82,875	81,837
Cumulative AT Cash Flow		1,293,227	1,383,617	1,527,734	1,658,704	1,771,681	1,874,251	***1,967,535***	***2,050,409***	***2,132,247***
PV Of Cash Flows	8.93%	1,187,224	76,179	111,504	93,026	73,668	61,400	51,264	41,811	37,903

		15 Yrs	20 Yrs	25 Yrs	30 Yrs
NPV 30 years	8.93%	(73,536)	(34,844)	101,927	192,367
IRR (After Taxes)		7.59%	8.34%	10.20%	10.96%

Q. Have you conducted an exhaustive assessment of the GridSolar proposal?

A. No. I have not attempted to exhaustively analyze the workings of the GridSolar financial model, and I have not reviewed all relevant literature on solar PV cost projections, for example. The model is highly sensitive to input assumptions, as would be expected, and thus it is critical for one to carefully assess the inner workings of the model before relying on it. I used this model to demonstrate the sensitivity of the results to key factors that are at best uncertain at this point in time, and to show that a not unreasonable set of assumptions can lead to economically feasible outcomes.

Q. What are your key observations concerning the GridSolar proposal?

A. Elements of the GridSolar proposal can play a very important role in designing a non-transmission alternative for Maine that could be less expensive than the effect of building MPRP. Waiting a few more years before ramping up the installation of solar PV can have significant cost-saving benefit, based on some projections of solar PV costs. In effect, as long as real costs of solar PV are declining due to technological and market driven changes, it is best to wait to install the solar PV as long as other resources - DR and EE - are able to maintain peak load at or below the threshold level for reliability without MPRP. As I have indicated elsewhere in this testimony and in my direct testimony, incorporating aggressive EE and DR resources could allow for the scope of the MPRP proposal to be reduced considerably. The use of solar PV as part of such a plan could prove an attractive and economically feasible alternative to a "stand alone" MPRP.

Q. Does this conclude your testimony?

A. Yes.

Attachments