STATE OF MAINE

PUBLIC UTILITIES COMMISSION

Docket No. 2008-255

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

Direct Testimony of Robert Fagan

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List of Discovery Responses Used

OPA-01-01	OPA-04-01	EX-01-16	CES-01-01
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OPA-02-01	OPA-04-06	EX-02-30	CES-01-17
OPA-02-03	OPA-04-09	EX-04-08	CES-02-01
OPA-02-05	OPA-05-01	EX-06-10	CES-02-03
OPA-02-06	OPA-05-02	EX-06-14	CES-02-07
OPA-02-07	OPA-05-03	EX-07-06	CES-02-09
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through		EX-07-17	CES-02-12
OPA 03-07		EX-07-43	CES-02-13
		EX-07-49	CES-02-15
			CES-02-17
		ODR 03-35	CES-02-21

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. Mr. Fagan, please summarize your educational background and recent work experience.

A. I am an energy economics analyst and mechanical engineer with over 20 years of experience in the energy industry. My work has focused primarily on electric power industry issues, especially economic and technical analysis of competitive electricity markets development, electric power transmission pricing structures, and assessment and implementation of demand-side resource alternatives. I hold an M.A. from Boston University in Energy and Environmental Studies and a B.S. from Clarkson University in Mechanical Engineering. A copy of my current resume is attached to this testimony.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to critique portions of CMP's Certificate of Public Convenience and Need application for its proposed Maine Power Reliability Project (MPRP). I focus primarily on CMP's Non-Transmission Alternatives (NTA) Assessment (Exhibit I-3), but I also address planning issues that arise in other areas of the MPRP application.

Q. Please explain how you conducted your analyses.

A. I reviewed CMP's application materials and responses to discovery, and attended technical conferences by phone or in person. I worked in close cooperation with my colleague Peter Lanzalotta, who is also sponsoring testimony on behalf of the Maine Office of Public Advocate in this proceeding.

Q. What discovery responses did you rely upon in developing your testimony?

A. My reliance includes but is not limited to the following responses, some of which are directly referenced or noted throughout my testimony, and others of which formed part of my background understanding:

OPA-01-01	OPA-04-01	EX-01-16	CES-01-01
OPA-01-03	through	EX-02-03	through
OPA-02-01	OPA-04-06	EX-02-30	CES-01-17
OPA-02-03	OPA-04-09	EX-04-08	CES-02-01
OPA-02-05	OPA-05-01	EX-06-10	CES-02-03
OPA-02-06	OPA-05-02	EX-06-14	CES-02-07
OPA-02-07	OPA-05-03	EX-07-06	CES-02-09
OPA 03-01	OPA 07-01	EX-07-07	CES-02-10
through		EX-07-17	CES-02-12
OPA 03-07		EX-07-43	CES-02-13
		EX-07-49	CES-02-15
			CES-02-17
		ODR 03-35	CES-02-21

Q. Please summarize your testimony.

A. CMP has failed to demonstrate a need for the MPRP. While there may be a need to incrementally improve CMP transmission system reliability using transmission system reinforcements or a combination of transmission and non-transmission upgrades, I have been unable to make such a determination because of the manner in which the MPRP was presented and the limited time in the schedule. CMP should revise its planning criteria and resubmit its MPRP proposal based on those criteria and with consideration of the critiques and recommendations I make in this testimony and Mr. Lanzalotta makes in his.

My testimony critiques several areas of CMP's NTA Assessment, focusing on the modeling construct, the inputs used, and the planning assumptions that underlie CMP's analysis. I summarize the body of my testimony as follows:

1. **Overly Stringent Planning Criteria**. The planning criteria used by CMP to define the parameters for non-transmission solutions are overly stringent, and thus the quantity of NTA generation resources proposed as an alternative to CMP's proposed transmission solution is too high. The NTA analysis applies planning criteria used in CMP's Needs Assessment (Exhibit I-1) by defining "threshold load levels" in each broad area (Northern, and Southern CMP regions) and in

individual sub-areas (Western Maine, Winslow-Skowhegan, Midcoast, Lewiston Loop, South Portland Loop). "Threshold load levels" represent CMP's purported maximum load levels in an area or sub-area that can be reliability served before additional NTA resources are required. The overly stringent nature of these criteria is explored in more detail in Mr. Lanzalotta's Direct Testimony, but its effect is clearly and dramatically seen: CMP's "threshold load levels" for 2017 for the northern and southern Maine regions combined (i.e., all of CMP's territory) is 1,277 MW, far below CMP's 2008 90/10 projected load that exceeds 1,800 MW. If CMP's threshold load levels were correct, it would imply that CMP is currently in severe violation of reliability criteria.[1] To accurately assess the cost of non-transmission solutions, the NTA Assessment would first need to be updated to reflect more appropriate "threshold load levels" that properly represent reliability criteria.

2. **No Hybrid Solution Assessment**. The NTA Assessment does not analyze hybrid solutions to reliability concerns that encompass a cost-effective mix of transmission, generation, special protection systems ("SPSs"), energy efficiency and demand response elements. Notably, the NTA Assessment does properly include analysis of VAR support resource options when determining other NTA resource needs. However, for example, there are no transformer or circuit upgrades, or SPS effects, included in any of the NTA Assessment solutions even when such an inclusion might be cost-effective. The exclusion of SPS resources *that already exist* is a particularly egregious omission from the NTA Assessment.

The cost of the integrated NTA solution (using dynamic VAR support) presented by CMP depends on 1,460 MW (nameplate) of incremental generation quantity required by 2027, including 800 MW by 2012. This amount of generation is in addition to Maine's roughly 3,200 MW of existing generation. Thus by CMP's reckoning, absent the MPRP the State of Maine would require in 2012 approximately 4,000 MW of generation to serve a peak load of about 2,360 MW,

[1] It is not clear from the material submitted by CMP if they believe that they are currently in violation of reliability criteria.

which equates to a planning reserve margin of 69%. This is far in excess of traditional utility planning reserve margins, and is *prima facie* evidence in support of our assertion that the planning criteria are overly stringent. To properly assess the extent to which a hybrid solution might be the most cost-effective alternative to meet reliability needs, CMP needs to test the economic effect of including elements such as the existing SPSs when assessing NTA resource requirements.

3. **NTA is Cheaper than Socialized Transmission**. Even if one were to accept CMP's overly stringent planning criteria, and thus accept the pattern of resource need currently included in CMP's Exhibit I-3, CMP's conclusion that their preferred transmission solution is more cost effective than the NTA solution is incorrect because their analytical method used to compare transmission with non-transmission solutions is flawed. Contrary to CMP's representation, the integrated non-transmission solution (NTA v2) presented in CMP's Exhibit I-3 is actually less expensive, not more expensive, than CMP's preferred transmission solution (TS_EE) by $56 to $333 million (NPV, $2008) depending on the assumption made concerning the ISO NE FCM price effect arising from surplus generation in Maine. CMP's analytical results erroneously concluded that the transmission solution was $416 million (NPV, $2008) less expensive than the NTA v2 solution.

The NTA model is analytically flawed. The NTA model is internally inconsistent between 1) the way it charges load for capacity cost obligations associated with the FCM and 2) the way it credits generation capacity for revenue received through the FCM. It presumes that load pays the full FCM price for its entire obligation, yet it only assumes that one-half of the NTA generation receives this FCM price. It presumes no partial "self-supply" of FCM obligations from presumably ratepayer-funded NTA generation. Notably, the model also ignores the presence of considerable surplus generation in Maine arising from the NTA solution and the way the "export-constrained" Maine capacity market would function in this scenario.

Given that forward capacity market costs make up 16.5% of the total net costs[2] to Maine ratepayers (second only to energy costs in CMP's makeup of societal cost components) for CMP's preferred transmission solution (TS_EE) it is not surprising that capacity market effects are critical to the analysis. It is surprising that CMP did not explore this facet of the NTA analysis more thoroughly. This aspect of the NTA analysis, if corrected, would change the resulting cost-effectiveness of the NTA solution, making it less expensive than the transmission solution even when accepting all the other assumptions made by CMP.

4. **FCM Effects of NTA Outweigh Superficial "Socialization" Benefits**. Non-transmission alternatives are cheaper than transmission even though Maine ratepayers would pay the full costs for NTA generation, and only a "Maine share" of 8% for the MPRP if its costs were fully socialized across ISO NE customers. While CMP literally highlights the "Capital Expenditures" effect when presenting the "Integrated Solution Summary of Evaluation Results" in Exhibit I-3 (page 4, page 7 of 464), its superficial indication – that the NTA is very costly, and the MPRP socialization effect is a boon to Maine customers – is belied by a more careful examination of total costs and the effect NTA generation has on FCM costs for Maine ratepayers.

5. **Modeled Demand Response is Too Low**. The level of maximum achievable demand response in Maine, estimated in the GDS Associates report (Exhibit I-3, Appendix A) at 179 MW of summer peak reduction by 2017, and estimated in the NTA Assessment at 188 MW by 2017, is far less than what would be expected when considering the current market for demand response potential as reflected by the results of the first two forward capacity market auctions held by ISO NE. The GDS report used an engineering-based approach to estimate demand response, including estimation of "participation rates"[3]. The ISO NE FCM results provide a more empirical, market-based test of the level of demand response resources available in Maine.

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[2] See Table 5. The range of total net cost share for capacity is 14.5% to 16.9%.
[3] Exhibit I-3, Appendix A, page 65 (page 225 of 464).

The second ISO NE FCM auction held in December 2008 indicates that for the 2011-2012 period, demand response resources in Maine are *already committed* to providing 294 MW of firm summer load reduction (or in some cases, emergency generation). Additional qualified demand response resources did not clear in the 2011-2012 auction; 485 MW of Maine zone demand resources qualified to bid in the 2nd FCA auction, yet only 294 MW cleared. This means that almost 200 MW of demand resources may still be *currently* available for participation in Maine, and this is without any concerted effort on the part of CMP to secure demand response commitments for the purpose of reliable system operation in the future. The evidence of potentially greater levels of demand response availability, through the FCM mechanism or through more traditional utility-based means of obtaining demand response, could result in significant increases in Maine demand resources by 2017, well above CMP's modeled level of 188 MW.

6. **Unrealistically Low Existing Generation Availability**. Several of CMP's "dispatch scenarios" used directly in the transmission needs assessment (Exhibit I-1) and indirectly in the non-transmission alternatives assessment (Exhibit I-3) are overly restrictive and should not be used as a basis for determining either transmission or non-transmission alternative needs. Scenarios D4 and D5 make available just 55% and 47% (respectively) of the maximum capacity listed for Maine generation, and assume 6 and 7 (respectively) Maine fossil units out of service, in addition to wind and hydro generation restricted output. All of this capacity currently participates in the ISO NE FCM market and is contractually obliged to be available for operation unless it is on forced or scheduled outage. It is unreasonable to plan for a scenario where this much capacity is not available to help maintain reliable operations during summer peak periods.

7. **Load Forecast Concerns**. CMP's load forecasts from 2007 and 2008 are out of date. Recent ISO NE updates illustrate the beginnings of the dramatic effect on load that will be caused by the current economic crisis (see ISO NE Planning Advisory Committee materials, January 21, 2009, at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2009/jan212009/index.html). Also, CMP's modeling of industrial load inappropriately increases

industrial load commitment by approximately 200 MW in 2017. When updating its analysis to properly reflect reasonable planning criteria, at that time CMP also needs to revisit load forecast assumptions.

Non-Transmission Alternatives Assessment – Methodology and Inaccuracies

Q. What is the Non-Transmission Alternatives ("NTAs") Assessment?

A. Exhibit I-3 of CMP's application is the NTA Assessment. It presents analyses of various alternative resource configurations ("ARCs") as an assessment of "non-transmission" solutions to CMP's asserted reliability needs.

Q. Did CMP summarize the alternative resource configurations presented as non-transmission solutions in the NTA Assessment?

A. Yes. CMP presents an "Integrated Solution Summary of Evaluation Results"[4] that first lists two transmission solutions, followed by three "integrated" NTA solutions. Each NTA solution is composed of a set of ARCs. Table 1 below contains an abbreviated description of these five solutions.

Table 1. Description of MPRP Transmission and NTA Solutions

MPRP Integrated Solution Designation	Description of Solution
TS (Transmission Solution)	Base transmission solution.
TS_EE (Transmission Solution plus incremental energy efficiency resources)	Base transmission solution, but including additional energy efficiency installations beyond projected Efficiency Maine plans.
NTA w/o VAR Supplies (Non-Transmission Alternative without reactive support resources)	Base non-transmission solution, without using any VAR support resources.
NTA with VAR Supplies V1	Base non-transmission solution, using static VAR supply solutions.
NTA with VAR Supplies V2	Base non-transmission solution, using dynamic VAR supply solutions.

Source: Exhibit I-3

[4] Exhibit I-3, page 4 (page 7 of 464).

Q. **Does the NTA Assessment compare the relative economics of transmission solutions to non-transmission solutions?**

A. Yes. The primary means of comparing the cost of the transmission solutions to the cost of non-transmission solutions is through examination of the "Societal Costs to Maine Ratepayers"[5]. This metric is first presented by CMP in Exhibit I-3 (at page 4, or page 7 of 464 at the top), and is the net present value (in $2008) of the stream of costs (and benefits) between 2008 and 2027. For each of the five solutions, the net present value consists of the sum of numerous components, listed in Table 2 below, presented along with the "category of cost" in which CMP placed them, and a brief description of how each was computed.

Q. **Is this framework a reasonable one for comparing costs of alternative solutions?**

A. Yes, it is, to a degree. The framework attempts to account for the total costs seen by ratepayers, over an extended period of time, for reliable electricity service under the different alternative configurations.

[5] Exhibit I-3, page 46 (page 49 of 464).

Table 2. CMP's NTA Assessment Cost Components

Category of Cost	Individual Component Definition	Definition
LSE costs, net of DSM NTA savings	energy costs	hourly loads for ME multiplied by LMPs
	FCM costs	annual summer peak load for ME multiplied by FCM rates
	FRM costs	ME share of ISO-NE required operating reserves
	AS costs	annual GWH for ME LSEs multiplied by AS rates
	OATT payments w/o MPRP	peak loads multiplied by PTF Rates
	REC purchases	post DSM energy times REC % times REC prices
New NTA Generators	recovery of invested capital	annual carrying charges
	fixed O&M	fixed O&M
	(FCM/FRM revenues)	summer capability multiplied by assumed FCM/FRM rates
	(net energy revenues)	energy market revenues less variable costs of production
New reactive power supply	static	annual carrying charges plus O&M
	dynamic	annual carrying charges plus O&M
TOs / CMP	recovery of MPRP invested capital	ME share of annual carrying charges
	fixed O&M for MPRP	ME share of fixed O&M
EE	recovery of "utility" portion of EE costs	utility incentive payments plus program admin costs
	(avoided T&D costs)	peak load savings multiplied by EMe avoided T&D rate
	customer share of EE costs	Cost of DSM measures not covered by incentives
	(non-electric EE benefits)	benefits other than electric savings
DR	recovery of DR costs	annual program costs

Source: Exhibit I-3, page 46 (page 49 of 464).

Q. Does the analysis itself result in a credible and reasonably accurate result?

A. No. I have identified three analytical weaknesses that undermine the conclusion that CMP draws, which is that a transmission solution as they have proposed is the least cost means to achieve the purported reliability need.

Q. What are those weaknesses?

A. 1) There are no alternative solutions analyzed that contain a combination of resources (e.g., incremental energy efficiency, demand response, selective transmission upgrades, selection generation installations, use of existing Special Protection Systems); instead, each of the alternatives generally exclude consideration of components from the "competing" alternative that could help to minimize overall costs[6].

2) The NTA Assessment inaccurately models forward capacity market effects on societal costs to Maine ratepayers. Even if one accepts CMP's assumptions that 1,460 MW of generation would be needed by 2027, the NTA Assessment significantly and incorrectly discounts the value of that generation. It arbitrarily assumes only 50% of NTA resources receive FCM revenues. CMP's analysis does not allow NTA generation to "self-supply" Maine load, i.e. to meet a significant portion of the obligation Maine load otherwise incurs for forward capacity market requirements.

This modeling flaw results in a materially significant overstatement of the net costs of the NTA alternatives relative to the transmission solution. If corrected by applying a consistent framework to the valuation of new Maine generation resources and their affect on FCM cost obligations, the NTA alternative is less expensive than the transmission solution alternative, even across a range of assumptions one may make on NTA generation's price effect on the FCM market.

This result is true even though Maine ratepayers would pay the full costs for NTA generation, and only a "Maine share" of 8% for the MPRP if its costs were fully socialized across ISO NE customers. While CMP literally highlights the "Capital Expenditures" effect when presenting the "Integrated Solution Summary of Evaluation Results" in Exhibit I-3 (page 4, page 7 of 464), its superficial indication – that the NTA is very costly, and the MPRP socialization effect is a

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[6] I note that CMP's preferred transmission solution does contain a small amount of new "NTA" generation, 40 MW of nameplate generation installed over the period 2022-2027.

boon to Maine customers – is belied by a more careful examination of total costs and the effect NTA generation has on FCM costs for Maine ratepayers.

3) The planning assumptions used are not reasonable. An updated analysis is required with more reasonable assumptions for i) threshold load levels, ii) dispatch scenarios, iii) demand response resources, and iv) load forecasting.

Q. Can you explain these three weaknesses in more detail?

A. Yes. I first present CMP's detailed results and make observations on the source of cost differences between CMP's base case NTA and transmission solutions. I then describe the weaknesses in more detail.

CMP's NTA Assessment Results - Integrated Solutions

Q. Does CMP directly compare the costs of these five alternative solutions to each other?

A. Yes, in their Integrated Solution Summary table[7]. I reproduce a portion of that table below in Table 3, showing CMP's summary values.

Table 3. ME Ratepayer Societal Cost - CMP Transmission and NTA Solutions

NPV 2008-2027, $2008 millions	Transmission -Base (Efficiency Maine EE Savings Only)	Transmission - Base + Incremental Energy Efficiency	NTA w/o VAR	NTA with Static VAR	NTA with Dynamic VAR
Maine Societal Costs	11,871	11,653	12,304	12,039	12,070

Source: Exhibit I-3, page 4 (page 7 of 464).

In particular, the cost of either of the first two transmission solutions can be compared to the cost of any of the three NTA solutions presented by CMP. CMP states that the transmission solution "produces favorable results, and represents an attractive choice, relative to the integrated NTA solutions studies" based upon their comparison of the costs of these five alternatives.[8]

[7] Exhibit I-3, page 4 (page 7 of 464).
[8] Exhibit I-3, page 134 (page 137 of 464).

Q. What do CMP's detailed comparative results show?

A. The following Table 4 lists CMP's detailed results. The third-from-bottom line, "Net Societal Costs to Maine Load", is the same as presented in CMP's NTA analysis summary table reproduced above as Table 3. It shows, for example, that the net present value ("NPV")[9] of CMP's transmission solution is $11.87 billion (in $2008), and that an NTA solution would range from $12.04 billion (with static VAR) to $12.30 billion (no VAR support). The next-to-bottom line of Table 4, "Change in Costs Relative to Transmission Solution" indicates the percentage change in overall NPV costs associated with each of the last four solutions, relative to the first "Transmission Solution", based on CMP's assumptions. It shows, for example, that CMP claims the NTA solution utilizing dynamic VAR resources would be 1.7% more costly (NPV basis) than the transmission solution. As I show in Table 9 and its accompanying narrative, CMP's claim is incorrect and the dynamic VAR solution is actually less costly than either of CMP's transmission solutions shown here.

Table 4 clearly shows the relative contribution to costs of each of the components. Energy costs make up the bulk of costs to Maine ratepayers. Notably, as shown in the bottom line of Table 4, capacity market costs are the second most costly component, representing approximately 14.5%-16.9% of total ME Societal Costs.

The sources for the values in this table are the "NPV summary" tables that are a separate worksheet in each of five files provided in response to EX-07-06, Attachment 1.

[9] The net present value is computed as the discounted stream of costs and benefits associated with each component of the Maine Societal Cost, and is calculated over the period 2008-2027. No accounting is made for the net effect of the NTAs on NPVcosts for time periods beyond 2027.

Table 4. NPV of CMP's Five Alternative Solutions: by Cost Component

NPV '000 of $2008		Transmission Solution Costs		Non-Transmission Alternative Solutions Costs		
Category of Cost	**Component of Cost**	**Base (Eff. Maine EE Savings Only) "TS"**	**Base + Incremental Energy Efficiency "TS_EE"**	**NTA w/o VAR**	**NTA with Static VAR**	**NTA wit h Dynamic VAR "NTA v2"**
LSE Costs, Net of DSM NTA Savings	energy costs	8,390,561	8,205,567	8,203,164	8,213,314	8,213,314
	FCM costs	2,004,936	1,924,290	1,781,276	1,781,276	1,781,276
	FRM costs	183,765	178,287	178,287	178,287	178,287
	AS costs	264,493	256,974	256,974	256,974	256,974
	OATT payments w/o MPRP	747,404	720,930	669,949	669,949	669,949
	REC purchases	202,586	195,369	195,369	195,369	195,369
	risk premia / margin	-	-	-	-	-
New NTA Generators	recovery of invested capital	6,777	6,777	1,005,360	718,223	718,223
	fixed O&M	437	437	152,225	86,828	86,828
	(FCM/FRM revenues)	(1,936)	(1,936)	(295,717)	(290,257)	(290,257)
	(net energy revenues)	(6,281)	(6,272)	(76,303)		(15,127)
New reactive power supply	static	-	-	-	11,103	-
	dynamic	-	-	-	-	41,635
MPRP Costs Maine Share	recovery of MPRP invested capital	64,050	61,486	-	-	-
	fixed O&M for MPRP	14,156	13,590	-	-	-
Energy Efficiency	recovery of "utility" portion of EE costs	-	90,586	90,586	90,586	90,586
	(avoided T&D costs)	-	(52,962)	(52,962)	(52,962)	(52,962)
	customer share of EE costs	-	76,874	76,874	76,874	76,874
	(non-electric EE benefits)	-	(17,052)	(17,052)	(17,052)	(17,052)
Demand Response	recovery of DR costs	-	-	135,597	135,597	135,597
NET SOCIETAL COSTS TO MAINE LOAD		**11,870,947**	**11,652,945**	**12,303,627**	**12,038,983**	**12,069,515**
Change in Net Societal Costs Relative to "Transmission Solution"		0.0%	-1.8%	3.6%	1.4%	1.7%
FCM Costs as Share of Net Societal Costs to ME Load		16.9%	16.5%	14.5%	14.8%	14.8%

Source: CMP. Five excel files provided in response to EX-07-06 Attachment 1, MPRP Scorecard Model v10: ME-TS, ME-TS_EE, ME-NTAnoVAR, ME-NTAv1, ME-NTAv2. "NPV summary" worksheet on each of the five files. Also from Exhibit I-3, Appendix F, page 79-83 (page 460-464 of 464).

Q. Have you examined more closely CMP's comparison between a transmission solution and an NTA solution?

A. Yes. To illustrate the source of CMP's claimed cost differences between CMP's proposed transmission solution and CMP's NTA solution, I set forth the differences between CMP's TS_EE case and CMP's dynamic VAR NTA case in Table 5 below. Table 5 highlights the results of this comparison, and includes my observations on the source of the cost difference for each component.

Table 5. Comparison Between CMP's TS_EE and Dynamic VAR NTA Solution

NPV '000 of $2008 **Component of Cost**	**TS_EE**	**NTA v2**	**Cost Difference NTA VAR 2 minus TS_EE**	**Observations on Source of Cost Difference**
energy costs	8,205,567	8,213,314	7,747	LMPs lower; overall DSM savings lower (DR effect) for TS_EE
FCM costs	1,924,290	1,781,276	-143,014	DR resource lowers MW obligation. Same FCM price used.
FRM costs	178,287	178,287		
AS costs	256,974	256,974		
OATT payments w/o MPRP	720,930	669,949	-50,981	DR resource lowers MW obligation
REC purchases	195,369	195,369		
risk premia / margin	-	-		
recovery of invested capital	6,777	718,223	711,446	NTA generation fixed cost higher. 40 MW gen. in TS_EE.
fixed O&M	437	86,828	86,391	NTA generation O&M higher.
(FCM/FRM revenues)	(1,936)	(290,257)	-288,321	Crediting of FCM revenues to 50% of NTA generation.
(net energy revenues)	(6,272)	(15,127)	-8,855	NTA generation net revenues.
Static VAR	-	-		
Dynamic VAR	-	41,635	41,635	NTA cost of dynamic VAR.
MPRP invested capital recovery	61,486	-	-61,486	Maine load share of MPRP capital costs.
fixed O&M for MPRP	13,590	-	-13,590	Maine load share of MPRP O&M
Utility EE cost recovery	90,586	90,586		
(avoided T&D costs)	(52,962)	(52,962)		
customer share of EE costs	76,874	76,874		
(non-electric EE benefits)	(17,052)	17,052)		
recovery of DR costs	-	135,597	135,597	GDS estimated cost of DR.
NET SOCIETAL COSTS TO MAINE LOAD	11,652,945	12,069,515	416,570	Sum total effect of above differences

Source: Response to EX-07-07; Synapse computation.

Q. Describe the differences in the physical resources CMP used for the transmission solution compared to what CMP used for the non-transmission solution.

A. CMP's NTA solution differs from CMP's transmission solution primarily by the addition of 1,460 MW of nameplate generation between 2012 and 2027, consisting of a mix of 1,275 MW of peaking combustion turbines (12-100 MW, and 3-25 MW), and 185 MW of smaller-scale CHP and wood-fired generation.[10] This generation is added between 2012 and 2027, with 800 MW added in 2012, 190 MW added between 2013 and 2020, and the remaining 470 MW added between 2020 and 2027.[11] (The transmission solution evaluated in the NTA assessment includes a total of 40 MW of combined heat and power generation resources added in four 10 MW increments between 2022 and 2027.[12]) The non-transmission alternative (using dynamic VAR resources - "NTA V2") also includes the addition of 117 MVAR of dynamic reactive resources, installed between 2012 and 2024[13]. The NTA solution also contains 229 MW of demand response by 2027.[14] The NTA solution does not contain any of the capital and operating costs of the MPRP solution, as no MPRP transmission elements are included. For this comparison, all energy efficiency resource effects are the same between the two solutions.

Q. Table 5 shows the cost differences between CMP's transmission and non-transmission alternatives. Can you explain the source of those differences?

A. Yes. As shown in Table 5, the NTA solution capital costs for generation are $711 million (NPV, $2008) more than for the transmission solution (noted as "recovery of invested capital" in the Table 5's "Component of Cost" column). This cost increase is partially offset by $290 million (NPV, $2008) in FCM revenues received by the NTA generation ("FCM/FRM Revenue"), according to CMP's

[10] EX-07-06, MPRP Scorecard Model v10 - ME-NTA v2, "NTA Generation" worksheet.
[11] Ibid.
[12] EX-07-06, MPRP Scorecard Model v10 - ME-TS_EE, "NTA Generation" worksheet.
[13] EX-07-06, MPRP Scorecard Model v10 - ME-NTA v2, "dynamic reactive" worksheet.
[14] EX-07-06, MPRP Scorecard Model v10 - ME-NTA v2, "demand response" worksheet.

model. In this model, the FCM revenues for the NTA solution are arbitrarily based on 50% of the NTA generation quantity in each year between 2012 and 2027 receiving the full FCM revenue price in each of those years.[15] The remaining 50% of NTA generation is modeled as receiving no FCM revenue, and its presence does not change the FCM price applicable for Maine in the model. The NTA solution also adds $86 million in operating and maintenance costs for generation ("fixed O&M").

In CMP's NTA solution, the demand response resource adds $136 million (NPV, $2008) in costs ("recovery of DR costs"). CMP then shows that the effect of the demand response lowers the obligations for transmission tariff payments (by $51 million, "OATT payments w/o MPRP") and FCM obligations (by $143 million, "FCM costs") because the Maine peak MW load is lower in the NTA case. The NTA solution also avoids a total of $75 million (NPV, $2008) in MPRP capital and operating costs ("MPRP invested capital recovery" and "fixed O&M for MPRP"), while adding $42 million in dynamic VAR costs ("Dynamic VAR").

Notably, energy market effects are relatively small. The transmission solution lowers the NPV of "energy costs" (net of DSM effects) by lowering the overall LMPs (even net of the greater DSM savings seen in the NTA case, due to DR effects). This amount, $7.7 million (NPV, $2008), is more than offset by the "net energy revenues" received by the NTA generation, $8.9 million (NPV, $2008).

[15] EX-07-06, MPRP Scorecard Model v10 - ME-NTA v2, "NTA Generation" worksheet.

No Analysis of Hybrid Transmission / Non-Transmission Solutions That May Be Less Costly Than Stand-Alone Transmission or Non-Transmission Solutions

Q. You earlier referenced three analytical weaknesses of the NTA Assessment. Please explain the first weakness of the analytical modeling.

A. The first weakness relates to the way CMP has failed to properly analyze hybrid approaches that utilize both transmission and non-transmission elements to ensure reliable electricity service.

Q. Does CMP analyze hybrid transmission/non-transmission solutions that seek to combine the most cost-effective transmission and non-transmission elements to provide for reliability needs?

A. No. CMP states that it will compare non-transmission alternatives in a study separate from its "standalone backstop"[16] transmission solution. Even though CMP states that the non-transmission study will consider "hybrids of both transmission and non-transmission alternatives"[17], the NTA Assessment contains no evidence that such consideration was given to true hybrid solutions combining, for example, selected transmission system elements and targeted generation. In fact, CMP appears to take a step backward in this regard. CMP removes altogether the first and arguably most cost-effective means of reducing the need for new transmission elements in its approach by eliminating the existing Special Protection Systems used for northern Maine contingencies. This is exacerbated by CMP not directly modeling the presence of demand response resources and maximum energy efficiency savings. Thus, at the outset, CMP's transmission need modeling construct excludes existing resources; and relatively low-cost, new peak-load-reducing resources.

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[16] Exhibit I-1, page 3 (page 11 of 533), and I-2, page 3 (page 13 of 373).
[17] Exhibit I-1, page 3 (page 11 of 533).

Q. How do the physical components of the transmission and non-transmission solutions compare to each other?

A. Table 6 below lists the resources that the Transmission Alternatives Assessment, Exhibit I-2, and the Non-transmission Alternatives Assessment, Exhibit I-3, include as part of their respective solutions to reliability concerns.

Table 6. Elements of CMP's Transmission and Non-Transmission Solutions

Transmission Alternatives Assessment (CMP Exhibit I-2)	**Non-Transmission Alternatives (CMP Exhibit I-3)**
New 115 kV and __ kV capacitors (VAR resource)	Static and dynamic reactive compensation (VAR resource)
Energy Efficiency measures (Efficiency Maine current projections)	Energy Efficiency measures (Efficiency Maine current projections)
New 345 kV and 115 kV line construction	Incremental energy efficiency measures
Rebuilding of existing 115 kV lines	Demand response measures
Re-rating of 345 and115 kV lines	Generation: • Wood-fired biomass (25 MW) • Combined Heat and Power (<10 MW) • Combined Cycle (25 to 100 MW) • Combustion Turbine (10 to 100 MW)
New 345/115 kV autotransformers	
New or expanded substation construction	
Upgrade or reconfiguration of substations	
Separation of double circuit towers	

Source: Exhibit I-2, pages iv – vi (pages 4-6 of 373). Exhibit I-3, pages 2, 4, 41 (pages 5,7, 44 of 464).

Q. Is there significant overlap between the resources used in the transmission assessment and those used in the non-transmission assessment?

A. Generally, no, as can be seen by inspection of Table 6 above. While there is some use of efficiency and reactive support in the transmission solution set, there are no "wires" features in the NTA set, and no generation resources in the transmission solution set[18]. As noted, the transmission assessment states that it is a "standalone backstop" transmission solution when compared to the NTA analysis. And the NTA analysis states that "CMP sought an assessment of the reasonable alternatives to transmission solutions" and that it "examines alternatives that may come from the marketplace more generally"[19].

Q. Did CMP actually assume that non-transmission solutions would "come from the marketplace"? Please explain.

A. No, CMP did not assume that non-transmission solutions would come from the marketplace. In its accounting of the societal costs to Maine ratepayers for non-transmission solutions, CMP explicitly includes the recovery of the revenue requirement for NTA generation, as is shown by the line item "recovery of invested capital" in respect of new NTA generators in Exhibit I-3 Appendix F, pages 79-83 (pages 460 – 464 of 464).

Q. Was CMP's proposed transmission solution developed without incorporating any "non-transmission" resources, even existing ones?

Yes, excepting only Efficiency Maine existing conservation projections. The transmission solution is developed without incorporating any incremental energy efficiency (i.e., any energy efficiency in addition to Efficiency Maine current projections) and without any demand response or targeted generation resources or SPSs. While the NTA Assessment included a transmission solution ("TS_EE") that "analyzed an additional scenario where incremental EE resources were added to the transmission solution"[20] there was no analysis of transmission solutions in the transmission assessment that first accounted for any combination of incremental EE, demand response resources, or other "non-transmission" elements such as targeted generation or the retention of special protection systems.

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[18] With one minor exception: 40 MW of combined heat and power resources are present in the transmission solution, in 10 MW increments in each of 2022, 2024, 2025, and 2027.
[19] Exhibit I-3, page 8 (11 of 464).
[20] Exhibit I-3, page 2 (page 5 of 464).

Q. Were the non-transmission alternatives developed without incorporating any significant transmission resources?

Yes. The NTA solution is developed without any incorporation of identified line, transformer or substation upgrade or construction, with the exception of reactive resource (VAR) installations.

Q. How does the NTA analysis include reactive power resources?

A. The NTA analysis includes the installation of static and/or dynamic reactive support resources when considering the "threshold load levels" to which non-transmission solutions are applied.[21] This results in higher threshold load levels when such reactive support is directly included.

Q. The proposed transmission solution does not rely upon the installation of any energy efficiency beyond current Efficiency Maine projections, and does not include any demand response or targeted generation installation or SPSs anywhere in Maine, does it?

A. No, it does not.

CMP's NTA Assessment and Its Inconsistent Representation of FCM Construct

Q. You earlier referenced three analytical weaknesses of the NTA Assessment. Please explain the second weakness of the analytical modeling.

A. The second weakness relates to the way the NTA model accounts for interrelated aspects of new NTA generation and FCM obligations on Maine load. These are i) the cost of the generation, ii) the revenues NTA generation could see from the FCM, and iii) the cost to load to meet FCM obligations.

[21] Response to EX-07-07 Attachments 1-4.

Q. How does the NTA Assessment treat costs of the new NTA generation?

A. The NTA assessment assigns costs to new NTA generation to Maine ratepayers based on the estimated costs of construction or purchase, and ongoing operating costs. At this stage of my analysis, I do not take issue with the per unit cost estimates made by CMP or the way in which they are attributed to Maine ratepayers in the NTA modeling. Notionally, I interpret these costs as akin to traditional rate-based, "regulated" costs borne by Maine ratepayers, which are different from CMP's interpretation as referenced by the statement in Exhibit I-3 that "the NTA Assessment examines alternatives that may come from the marketplace more generally" [22].

As I address in the "threshold load level" subsection of this testimony, I question the accuracy of the overall quantity of NTA generation claimed to be needed to meet reliability needs. Also, if Maine load were to pay for the installation of 1,460 MW of generation through 2027, I would expect that the full capacity value of this generation would then be utilized to produce the lowest possible net capacity costs for Maine load – for example, by serving as self-supply for a portion of capacity obligations. As I show immediately below, the NTA modeling fails to give full credit to this resource in its accounting of costs for the non-transmission solution. It does not consider the NTA resource as a source for self-supply, even though the model does charge ratepayers the full capital and operating costs of the generation.

Q. How does the NTA treat FCM revenues for NTA generation?

A. The NTA assessment arbitrarily assumes that only 50% of each year's NTA generation quantity will receive FCM revenues. For the transmission solution, a small quantity of NTA generation is assumed installed in the 2022-2027

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[22] Exhibit I-3, page 8 (page 11 of 464). As noted earlier, CMP explicitly includes the recovery of revenue requirements associated with NTA generation costs in their NTA analysis, yet includes this statement that implies – inconsistent with their analysis – that NTA generation may come from the marketplace.

timeframe. Only 50% of this NTA generation is presumed to receive FCM revenues.

Q. Is this 50% assumption supported by any analysis of the ability of NTA generation in Maine to participate in the FCM or "clear" in the FCM auction?

A. No. The applicants state in Exhibit I-3 (at page 35, page 38 of 464) that the State of Maine is "export constrained", but they do not address in detail: (i) the nature of the export constraint, (ii) the fact that in the first two ISO NE FCM auctions the constraint was not binding[23], nor (iii) the interplay between FCM price in Maine and the level of generation capacity and the transfer limits between Maine the rest of the New England region.

Q. How does the NTA Assessment treat the costs to load to meet FCM obligations?

A. The NTA Assessment uses a simple formulation to determine "FCM Costs", as they are referred to in the detailed summary table I presented earlier as Table 5. These costs, computed on an annual basis, are the product of an assumed FCM price and an assumed peak MW load obligation for Maine customers, accounting for the effects of any energy efficiency or demand response. The NPV of the stream of annual costs between 2008 and 2027 is then computed.

Q. How does the NTA Assessment address future capacity market prices in Maine?

A. The NTA Assessment assumes the same forecast of FCM prices for both the transmission solution and the non-transmission solution, even though the non-transmission solution results in both a significant amount of new generation and reduced Maine-to-New Hampshire interface transfer limits, relative to the transmission solution. Both of these parameters would, in theory, potentially affect the clearing price of capacity in Maine.

[23] See the first two FCM auction results attached to this testimony and available at www.iso-ne.com.

Q. In theory, what effect would capacity additions in Maine, and the absence of major MPRP elements that would increase ME-NH interface limits, have on the Forward Capacity Market prices in the Maine zone?

A. Increased capacity resources in Maine, combined with lower transmission limits between Maine and the "rest of pool" in New England (i.e., via the ME-NH interface) would in theory put downward pressure on Maine capacity prices if a threshold is reached whereby the export limit for the Maine zone becomes binding in the FCM auction. Even without such a binding constraint, increased supply resources in the FCM auction can lead to lower FCM prices, all else equal, due to competitive pressure.

Q. What is the level of "existing generation" in Maine that currently qualifies as an ISO NE capacity resource?

A. The summer capacity of existing resources in Maine that qualify as ISO NE FCM resources is approximately 3,200 MW, as indicated in Table 7 below.

Table 7. Maine Generation Cleared in Most Recent ISO NE FCM Auction

Generation Station	Summer MW	Generation Station	Summer MW
AEI LIVERMORE	35	MIS 1-3	490
Aggregate Hydro	501	MMWAC	2
BAR HARBOR DIESELS 1-4	4	PERC-ORRINGTON 1	21
BORALEX STRATTON ENERGY	45	PPL GREAT WORKS - RED SHIELD	10
BUCKSPORT ENERGY 4	143	RUMFORD POWER	245
Cape GT 4 & 5	29	S.D. WARREN-WESTBROOK	41
EASTPORT DIESELS 1-3	3	SOMERSET	2
ECO MAINE	11	Verso VCG1 (Androscoggin Energy)	42
GREENVILLE	14	Verso VCG2 (Androscoggin Energy)	42
INDECK JONESBORO	23	Verso VCG3 (Androscoggin Energy)	42
INDECK WEST ENFIELD	23	Westbrook 1-3	516
Kibby, Record Hill and Longfellow Wind	45	WMRE Crossroads	3
MEAD (New Page)	45	WORCESTER ENERGY	17
MEDWAY DIESELS 1-4	6	Yarmouth 1-3	219
MERC	21	YARMOUTH 4	603
		Grand Total	**3,244**

Source: ISO NE auction results at http://www.iso-ne.com/markets/othrmkts_data/fcm/filings/index.html. Synapse aggregation of some resources.

Q. Can you illustrate the extent of "surplus" capacity in Maine that could result from the non-transmission solution?

A. Yes. The NTA Assessment solution (with VAR support) assumes that 1,460 MW of new capacity is installed in Maine, 800 MW (720 MW summer rating) in 2012 alone. With an NTA modeled peak load of approximately 1,966 MW in Maine in

2012 (adjusted for EE and DR), and existing FCM generation of approximately 3,200 MW[24], the presence of new NTA generation would result in a large surplus of generating capacity in Maine, beginning in 2012 when the first 800 MW (nameplate) of capacity is required according to CMP's NTA analysis. Table 8 below illustrates the level of "surplus" generation over and above Maine load needs and considering exports to the rest-of-pool over the Maine-New Hampshire interface.

Table 8. Surplus Generation in Maine Under CMP's NTA Solution

Year	NTA v2 - ME Peak Load Net of EE/DR, MW	Existing FCM Generation MW	New NTA Summer Capacity MW	Total Maine Generation MW	Surplus Before Accounting for Imports or Exports or Retirements	ME-NH Transfer Limit	Net Surplus in Maine MW
a	b	c	d	e = c + d	f =e - b	g	h=f-g (or 0, if -)
2008	1,878	3,200	-	3,200	1,322	1,600	-
2009	1,899	3,200	-	3,200	1,301	1,600	-
2010	1,917	3,200	-	3,200	1,283	1,600	-
2011	1,941	3,200	-	3,200	1,259	1,575	-
2012	1,966	3,200	720	3,920	1,954	1,550	404
2013	1,993	3,200	729	3,929	1,936	1,525	411
2014	2,021	3,200	752	3,952	1,931	1,500	431
2015	2,051	3,200	752	3,952	1,901	1,475	426
2016	2,082	3,200	752	3,952	1,869	1,450	419
2017	2,115	3,200	761	3,961	1,845	1,450	395
2018	2,164	3,200	860	4,060	1,896	1,450	446
2019	2,213	3,200	891	4,091	1,878	1,450	428
2020	2,263	3,200	891	4,091	1,828	1,450	378
2021	2,315	3,200	900	4,100	1,785	1,450	335
2022	2,368	3,200	1,031	4,231	1,862	1,450	412
2023	2,422	3,200	1,040	4,240	1,817	1,450	367
2024	2,477	3,200	1,058	4,258	1,780	1,450	330
2025	2,534	3,200	1,098	4,298	1,764	1,450	314
2026	2,592	3,200	1,116	4,316	1,724	1,450	274
2027	2,651	3,200	1,314	4,514	1,863	1,450	413

Sources: NTA model; FCM Auction #2; EX-06-14, Attachment 1, page 1 (transfer limits).

Q. Does the NTA analysis account for this level of surplus in Maine when developing "FCM costs" to Maine load?

A. No. The NTA analysis does not presume that surplus generation in Maine might lower capacity prices, and thereby lower FCM costs to Maine load under an NTA

[24] See Table 7 above.

solution. The NTA analysis not only uses the same capacity price for Maine as it does for the "rest of pool", it uses the same set of unconstrained, region-wide FCM prices for both the transmission solution and the NTA solution, even though the NTA solution dramatically changes Maine's capacity balance relative to the transmission solution. If there is more than 200 MW of surplus (i.e., net of *both* Maine peak load and capacity exports to the south) generation capacity in Maine in all years between 2012 – 2027, and generally more than 400 MW in between 2012 and 2019 this should put considerable downward pressure on the FCM price.

Q. Does the NTA analysis consider that rate-based generation, such as might be utilized in an NTA solution, could be used to "self-supply" a portion of Maine's FCM load obligation and thereby lower Maine load exposure to the effect of the FCM?

A. No, it does not. Notably, rather than first having Maine self-supply its obligation with ratepayer-funded NTA generation, it instead devalues this generation.

Q. Did you compute the net Societal Cost to Maine Ratepayers using CMP's NTA model with revised forward capacity market inputs?

A. Yes. Using the NTA spreadsheet model provided in response to EX-07-07, I modified the inputs to determine net "Societal Costs to Maine Ratepayers" that results when a more consistent framework for forward capacity market parameters is used. To illustrate the effect of using more consistent and logical approaches to FCM impacts, I used two alternative sets of inputs:

1. **Scenario 1.** All new NTA generation is first used to reduce Maine's FCM quantity obligation, effectively "self-supplying"[25] that part of the obligation and receiving no FCM revenue. The remaining Maine FCM cost obligation is priced at CMP's FCM price projection.

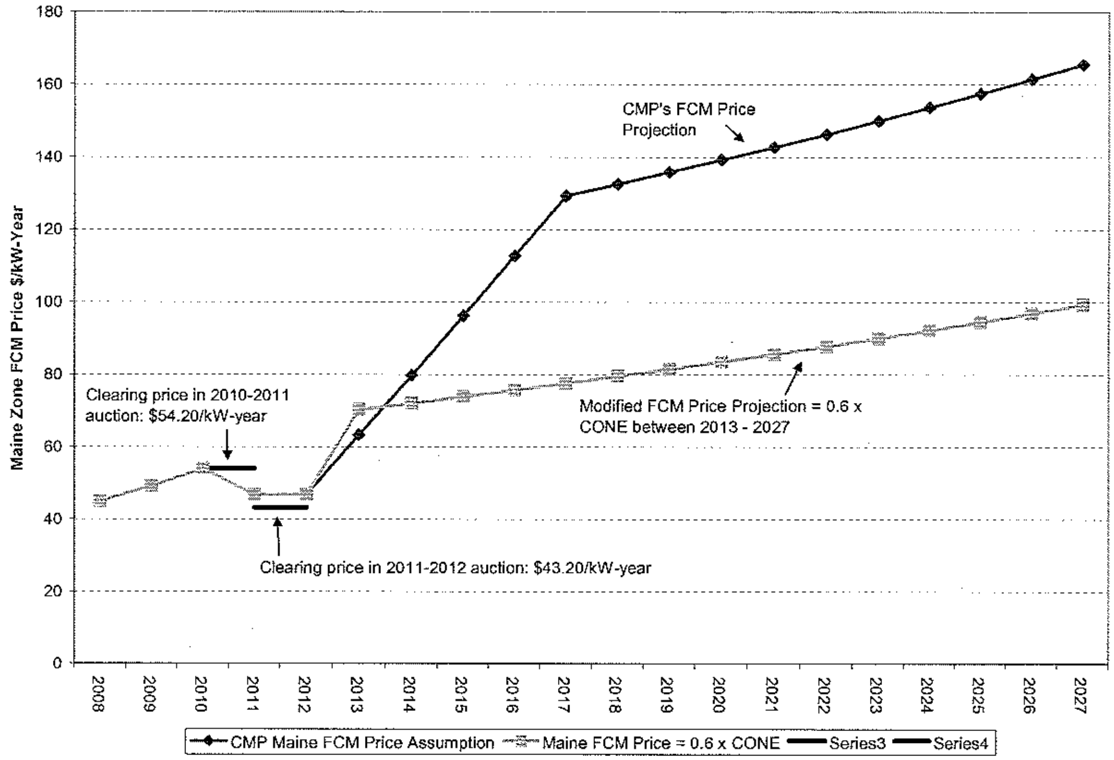
[25] ISO NE Market Rule 1, Section III.13.1.6, "Self-Supplied FCA Resources".

2. **Scenario 2.** As with my first assumption, all new NTA generation is first used to reduce Maine's FCM quantity obligation and receives no FCM revenue. I also illustrate a Maine zone FCM price effect that reflects Maine zone surplus generation. For the years 2014 through 2027, I used an estimate of 0.6 times CMP's estimated cost of new entry (CONE), reflecting one possible Maine zone price that could arise when the export constraint binds in the FCM auction.

Q. Please explain how you made these changes.

A. I made these changes by modifying the spreadsheet values in two different worksheets contained in the NTA v2 file provided as an attachment to the response to EX-07-07. The file and worksheet I first modified was MPRP Scorecard Model v10 – ME – NTA v2.xls. I modified the FCM quantity obligation by reducing the Maine summer peak load MW obligation by the cumulative quantity of summer generation provided by the NTA generation commencing in 2012. These changes were done in the "Maine LSE Items" worksheet. I then modified the "NTA Generation" worksheet by setting the "FCM/FRM" revenue total to zero. These two changes reflect the "Scenario 1" modifications noted above. For "Scenario 2" noted above, I kept the same changes as for Scenario 1, and added a further change by modifying the FCM price input assumption on the "inputs" worksheet to the same file. In that case, I set the FCM price to equal CMP's FCM price through year 2012, and then commencing in 2013 I set the FCM price equal to 0.6 times CMP's computed value of "cost of new entry" or CONE. Figure 1 below shows the modification to the FCM price pattern that I used for Scenario 2, along with CMP's FCM price projection.

Figure 1. Maine Zone FCM Price Projections



Source: CMP FCM Price: Exhibit I-3, page 35,(page 38 of 464). Modified FCM Price: computed by Synapse.

Q. Why did you use 0.6 times CONE as a modified FCM price input?

A. The current ISO NE tariff uses 0.6 times CONE as the minimum price for the FCM auction.[26] However, the "CONE" used by ISO NE in future auctions could be lower than the "CONE" used by CMP, depending on the year-to-year results of the auctions. Thus, my use of 0.6 times CONE as a minimum is actually conservative; surplus generation in Maine could drive the Maine zone FCM price to levels lower than those shown here.

Q. What were your results?

A. The following Table 9 shows my results.

[26] ISO NE Market Rule 1, Section III.13.

Table 9. TS_EE and NTA v2 Societal Costs With New FCM Assumptions

NPV $2008	TS_EE	NTA v2 with changes	Difference NTA – TS_EE (+ = TS_EE is less expensive)
CMP's Original	11,653	12,070	416 million
Scenario 1 – NTA generation reduces FCM obligation	11,650	11,593	-56 million
Scenario 2 – NTA generation reduces FCM obligation and NTA generation price effect in Maine zone	11,650	11,317	-333 million

Source: Synapse computation.

Q. What do these results illustrate?

A. CMP's original analysis, presented in their Exhibit I-3, shows an NTA solution that is $416 million (NPV, $2008) more expensive than their preferred transmission solution. If the 1,460 MW (nameplate) of NTA generation is first used to reduce Maine load's FCM obligation[27], and no FCM revenues are received for that generation, the result is a reduction in net quantity of FCM obligation, a reduced Societal Cost to Maine ratepayers, and an NTA solution that is $56 million *less expensive* than CMP's preferred transmission solution. If a price effect is then considered, whereby surplus generation in Maine helps to drive the FCM auction price lower, one feasible result is a Maine zone clearing price that reaches the tariff minimum of 0.6 times CONE. Such a price effect reduces the cost for all remaining FCM obligations for Maine load, lowers Maine load total FCM costs, and leads to an NTA solution that is $333 million (NPV, $2008) less expensive than CMP's preferred transmission solution. Thus, the results clearly indicate that a consistent framework for the NTA analysis that respects the economically-based, supply/demand framework of the FCM auction leads to an NTA solution that is less expensive for Maine ratepayers than a transmission solution.

[27] As described in ISO NE Market Rule 1, Section III.13.1.6.

Q. CMP also reports "Illustrative Rate Impacts" on the Integrated Solution Summary of Evaluation Results (Exhibit I-3, page 4, page 7 of 464). Does the illustrative rate impact also change when the NTA model is corrected for FCM effects?

A. Yes. Table 10 below shows how CMP's "Illustrative Rate Impacts" changes when FCM effects are corrected in the same way as I describe above. The illustrative rate impact is for a single year, 2017. For Scenario 1, while the 2017 rate impact for the NTA solution is slightly higher than the TS_EE rate impact, the illustrative NTA rate impact becomes lower than the TS_EE impact in 2020, and stays lower for the remainder of the period through to 2027. I also note that the 2017 rate impact for Scenario 2 is lower with the NTA solution than with the TS_EE solution.

Table 10. Illustrative Rate Impacts with Revised FCM Inputs

Illustrative Rate Impacts 2017 c/kWh	TS_EE	NTA v2
Original CMP	16.44	17.16
Scenario 1	16.44	16.59
Scenario 2	16.44	15.96

Source: NTA model with changed inputs reflecting Scenario 1 and Scenario 2 as illustrated in Table 9.

Q. Can you show the pattern of rate impact over the 2008-2027 period?

A. Yes. Figure 2 below illustrates the comparative rate impacts using CMP's model for those illustrative impacts.

Figure 2. Illustrative Rate Impacts Using CMP Model, 2008-2027

Source: NTA Model "CMP Rate Impacts" worksheet, TS_EE; Synapse changes to model for NTA scenarios 1 and 2.

Q. How did you re-compute the illustrative rate impacts?

A. I used the same NTA model as used by CMP, and I modified values in the "CMP rate impacts" worksheet. I note that the NPV of the FCM costs used in the "CMP rate impacts" worksheet is different from the NPV of the FCM Costs used in CMP's "summary NPV" worksheet.

Q. Given these results, should CMP implement an integrated NTA solution as described in Exhibit I-3?

A. No. As my colleague Peter Lanzalotta demonstrates in his testimony, CMP's Transmission Need assessment (Exhibit I-1) uses overly stringent planning criteria to come up with their proposed MPRP solution. CMP also uses this criteria to determine a "threshold load level" used in the NTA assessment to derive requirements for NTA generation quantity (after first accounting for peak load reductions available through incremental energy efficiency and demand response). The MPRP as proposed, and the NTA solution as presented, is premised on faulty planning criteria. A revised analysis by CMP is required to properly determine what transmission and/or non-transmission resources may be needed to meet future reliability needs.

Effects of Other Planning Assumptions on NTA Assessment

Q. What is the third weakness of the NTA methodology?

A. The third weakness is that the NTA Assessment depends upon faulty planning assumptions made that include i) threshold load levels, ii) generation dispatch scenarios, iii) demand response resources, and iv) peak load forecasts. Each of these is discussed in separate subsections below.

The first of these is a result of the transmission need studies described in Exhibit I-1 (Needs Assessment). Those studies effectively produce artificially low "threshold load levels" and lead to NTA resource needs that are artificially high. The second of these assumptions serves to underestimate available generation capacity, contributing to the low "threshold load levels" and leading to unnecessarily high NTA generation requirements. Underestimating demand response resource potential and overestimating peak load requirements also leads to an unnecessary increase in NTA generation requirements.

Quantity of NTA Generation and Use of "Threshold Load Level"

Q. What quantity of new generation does the NTA Assessment claim is necessary to meet reliability needs?

A. The NTA Assessment claims that 1,460 MW of new NTA generation is required between 2012 - 2027 for either the "dynamic VAR" or "static VAR" solution.[28]

[28] EX-07-07, MPRP Scorecard Model v10 - ME-NTA v2, and MPRP Scorecard Model v10 - ME-NTAnoVAR "NTA Generation" worksheet.

Q. How much NTA generation is associated with each of the NTA solutions, and at what time frames is the generation needed?

A. The NTA analysis indicates that for each of the three NTA solutions shown above, the following generation and VAR resources are required (and the costs for which are included in the resulting analysis):

Table 11. NTA Integrated Solutions – Generation Quantity Needed by Year

MW	Generation Added – Nameplate	
Year	No VAR case	V1 and V2 case
2012	800	800
2013	25	10
2014		25
2015		0
2016	50	0
2017		10
2018	125	110
2019		35
2020	25	
2021	25	10
2022	110	145
2023	25	10
2024	35	20
2025	35	45
2026		20
2027	135	220
Total	**1,390**	**1,460**

Q. Is this level of generation incremental to existing generation on the Maine system?

A. Yes. The only retirements considered and in place in the NTA analysis are those of the Wyman 1-3 units in 2009, and then the Wyman 4 unit in 2022.

Q. How does CMP determine that this amount of generation is required to meet reliability needs?

A. The NTA Assessment separately calculates the amount of required generation capacity in each of the two aggregate regions (Northern Maine, and Portland-Southern Maine) and in each of five sub-areas (Midcoast, Winslow-Skowhegan, Western Maine, Lewiston Loop, and South Portland Loop) based on a defined "threshold load level"[29]. CMP states that this threshold load level is determined based on the transmission reliability assessments initially for year 2017.[30] The threshold load levels are purported to be the maximum load levels that can be supported in an area before reliability violations begin to occur ("This load level became the target or threshold level to which NTAs must reduce demand on the transmission system", Exhibit I-3, page 17 (page 20 of 464)).

Q. What are the threshold load levels used by CMP for the aggregate "Northern Maine" and "Portland-Southern" regions?

A. The following Table 12 contains CMP's reported threshold load levels for the two major areas, Northern Maine and Portland-Southern Maine, and for its sub-areas. The table also shows 2017 projected peak load in each area and sub-area, and projected 2008 90/10 peak load based on CMP's Fall 2006 Outlook forecast.

Table 12. CMP's "Threshold Load Levels"

Areas	Threshold Load Level – 2017 - No VAR Support	Threshold Load Level – 2017 -with VAR Support	Projected 90/10 Reliability Peak, 2017	Projected 90/10 Peak Load, 2008
Northern Maine	790.0	790.0	1,200.0	1,060.8
Portland – Southern	487.1	487.1	1,029.4	784.5
Sub-Areas				
Western Maine	327.1	387.1	446.8	302.1
Midcoast	127.5	142.5	167.0	116.6
Winslow-Skowhegan	50.2	153.7	157.3	unknown
Lewiston Loop	71.3	121.3	133.9	90.6
S. Portland Loop	204.5	204.5	245.9	171.9

Sources: EX-07-07 Attachment 1; Exhibit B-2, "Extreme 90/10 Peak Load (MW) by CMP Service Center, Fall 2006 Outlook", page 12 of 20 (page 26 of 53). The Portland-Southern Maine projected peak load for 2008 is the sum of the summer peak load for the Alfred and Portland service centers. The Northern Maine projected peak load is the sum of the peak load for the remaining nine service centers listed in the noted table. Western Maine: Bridgton, Lewiston, 26.% x Farmington. Midcoast: 87.17% of Rockland. Lewiston Loop: 30% of Western Maine. S. Portland Loop: 39% of Portland service center.

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[29] For example, see the file "EX-07-07_Attachment_1_ARC_1_Construction_-CONFIDENTIAL_(200.xls", worksheet "Northern Maine 345 kV" cell C8 "threshold load level".
[30] Exhibit I-3, page 17 (page 20 of 464).

Q. Table 12 indicates that the "threshold load level" against which the NTA generation must reduce demand is considerably lower than what CMP projects for 90/10 peak load for 2008. Please explain.

A. The fact that CMP's threshold load levels against which non-transmission solutions must strive to lower demand are considerably lower than current 90/10 loads apparently means that CMP is applying the use of overly stringent planning criteria to develop the "threshold load level" for the NTA modeling exercise. This is not surprising, given that CMP is using the same criteria in its transmission need assessment, as described in the testimony of Mr. Peter Lanzalotta. For both the proposed MPRP transmission solution, and the presented alternative non-transmission solutions, the planning criteria are overly stringent.

Q. Where exactly do the "threshold load level" values that are used in the NTA Assessment come from?

A. The exact source of these values is unclear. CMP states that they are from the transmission assessments, but in response to ODR-03-35 the information provided by CMP is not sufficient to determine the exact source or derivation of the threshold load level values. The response to ODR-03-35 was provided initially on December 2, and then supplemented on December 8 and again on December 23. The final supplemental response did not answer the direct question seeking identification of the specific source or computation used to arrive at the threshold load level values seen in Table 12.

Generation Used for Dispatch Scenarios

Q. What does CMP use as base case generation availability assumptions for the transmission need assessment?

A. Table 13 lists CMP's assumptions for the major Maine generation:

Table 13. Maine Generation Availability Assumptions Used by CMP

		Dispatch Cases from CMP Assumptions					
Generation - MW	**Max**	**D1**	**D2**	**D3**	**D4**	**D5**	**D6**
MIS 1-3	545	545	545	0	545	545	0
Great Lakes Hydro	60	60	60	60	60	60	60
Stetson Wind	0	0	0	0	0	0	0
Bucksport G4	190	190	190	0	190	0	190
Northern (Kennebec) Hydro	237	142	48	142	237	48	142
Redington / Kibby Wind	135	90	135	0	135	0	90
Stratton Energy	48	48	0	48	0	48	48
SAPPI G1 and G2	51	51	51	51	51	51	51
AEI	36	36	36	36	36	36	36
Rumford Power	265	265	0	265	265	0	265
Androscoggin Energy	150	150	150	150	150	0	150
New Page G4	95	95	0	95	95	95	95
Central Androscoggin Hydro	32	32	10	32	32	10	32
Westbrook 1-3	545	0	545	545	0	0	545
Yarmouth 1-3	235	110	235	235	0	0	235
Yarmouth 4	635	635	635	635	0	635	0
Southern (Saco) Hydro	22	22	10	22	22	10	22
Total	3,281	2,471	2,650	2,316	1,818	1,538	1,961
Percentage of "Max" MW On-Line		75.3%	80.8%	70.6%	55.4%	46.9%	59.8%
Number of Fossil Generation Units* Off-line:		2	3	3	6	7	2

Notes: # of offline units includes only fossil units. MIS 1-3 and Westbrook 1-3 are considered one unit; Yarmouth 1-3 and Androscoggin Energy are considered 3 units.
Source: Table 4-1 Generation Summary for Summer Peak Load Base Cases, I-1 p 33/573, and Synapse computation. Number of offline units estimated by inspection.

Q. CMP assumes significant unavailability of generation for some of these dispatch cases. Are these generation units generally available as capacity resources for the New England market?

A. Yes. For example, in the most recent ISO NE forward capacity market auction[31], 3,244 MW of Maine generation "cleared" or were accepted as generation capacity resources for the period 2011-2012 (i.e., including the summer 2011 period), as shown in Table 7.

Q. Are these the same generation units as CMP presents as Dispatch Scenarios and as represented in your Table 13 above?

A. Generally, yes. There are some differences with wind and hydro. All of the fossil units present in Table 13 are committed to supply capacity in the ISO NE FCM for the period 2011-2012, as indicated in Table 7. The hydro units from Table 13 are also present as committed units in the FCM for the same period; Table 7 shows an "aggregate hydro" entry totaling 501 MW. There are only 45 MW of wind in the ISO FCM list, for Kibby, Record Hill, and Longfellow sites.

Q. If a generation resource clears in the ISO NE FCM, what obligations does it have to be available during peak load periods?

A. All generation units that clear in the ISO NE FCM assume the obligation of being available except during forced or scheduled outages. Generally, generation units do not go on scheduled maintenance outage during peak periods. While it is possible that one or more of the Maine units could be on forced outage, and hydro conditions could be low, it is not reasonable to assume scenarios where 40% to 53% of the total capacity of existing generation in Maine is unavailable, such as is seen with scenarios D4 through D6. Even when reviewing just fossil-fired resources, Table 13 above shows that for the most severe outage scenarios (D4 and D5), CMP is assuming that six or seven fossil generation units that have contractually committed to be available would be on forced outage.

Units with an FCM obligation must offer in to the day-ahead and real-time energy markets. That these units are not owned by CMP has no bearing on their ability to be available – they must be available, per contractual commitment, if they clear in the FCM.[32]

Q. Can you be certain that the generation that has cleared in ISO NE's FCM-2 will be available in later years, such as 2017?

A. No. However, it is not unreasonable to make the assumption that these units will continue to participate as capacity resources. CMP, in its NTA assessment, assumed only that the units at Yarmouth 1-3 would retire after 2009, and that Yarmouth 4 would retire in 2022.[33] However, as indicated by the results of the

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[31] FCM-2, held December, 2008. See results at http://www.iso-ne.com/markets/othrmkts_data/fcm/filings/fca2_monthly_obligation_%20including_zeros_v7.xls.
[32] ISO New England Market Rule 1, Section III.13.6.
[33] Exhibit I-3, page 28 (page 31 of 464).

recent FCM auction, Yarmouth units 1-3 in particular are committed as capacity resources for the summer of 2011.

Q. How does the quantity and pattern of generation availability assumed for the transmission need assessment affect the NTA Assessment?

A. The use of overly stringent dispatch scenarios where more than 50% of generation is not available contributes to unreasonably low "threshold load levels" and thus leads to unreasonably high NTA generation needs.

Q. Did you consider "modified dispatch" cases in your analysis?

A. Yes. The OPA requested (OPA-07-01) that CMP perform two revised load flow runs. One of those runs, for 2017, contained a modification to the scenario "D5" generation dispatch inputs ("Option 2" as described in Mr. Lanzalotta's testimony). This modification reflected an incremental change to one of the more severe generation availability scenarios used by CMP in its planning. The modified D5 scenario increased the availability of generation for the model while still retaining a relatively severe lack of generating capacity. The modified dispatch reflected a limited 115 kV supply but increased the total generation from 1,538 to 1,823 MW, an increase of 285 MW arising from "turning on" (in the model) of Yarmouth units 1-3 and one of the Androscoggin Energy 50 MW cogeneration units. The "modified D5" scenario still reflects only 55.6% of the maximum generating capacity for Maine units originally provided by CMP in its Table 4-1 (Exhibit I-1, page 25, page 33 of 573). This is reflected in the response to discovery question OPA-07-01.

Q. What were the results of the "Option 2" load flow runs from the response to OPA-07-01 and what implications do they hold for your testimony?

A. As described in Mr. Lanzalotta's testimony, the results of the 2017 load flow runs using OPA-modified assumptions indicated significantly reduced reliability violations on CMP's transmission system compared to CMP's 2017 case. This implies that under Option 2 assumptions, "threshold load levels" would be higher than CMP uses in its NTA analysis, because the modeled system without MPRP experiences much fewer violations and can actually support greater threshold loads than CMP indicates. This supports my contention that the threshold load levels in CMP's NTA Assessment are too low, and the CMP's NTA generation resource requirement is too high.

Demand Response in CMP Assumptions and DR in ISO NE FCM

Q. What level of demand response does CMP assume in its Needs Assessment (Exhibit I-1) for the MPRP?

A. CMP does not include any level of projected demand response in its Needs Assessment (Exhibit I-1). It includes only the peak savings effect of currently-projected Efficiency Maine conservation resources as an adjustment to load.[34] It includes the potential effect of demand response resources only in its non-transmission assessment.

Q. Are there demand response resources in Maine currently committed to provide future capacity for the system?

A. Yes. The most recent ISO NE Forward Capacity Market auction resulted in 294 MW of Maine-based demand response resources clearing the market for capacity provision in the Maine zone in 2011-2012 (capacity commitment period of June 1, 2011 – May 31, 2012). The resources are listed in Table 14 below:

[34] Response to OPA 03-05, "CMP's load forecast incorporates the conservation plan that Efficiency Maine expects to execute. Efficiency Maine provided savings estimates through 2010. CMP has assumed that incremental savings achieved in 2010 will be continued into the future."

Table 14. Maine Zone DR Resources Cleared in the ISO NE FCM Auction #2

Demand Response Provider Name	DR Type	Status	Summer
Huhtamaki	CP	Existing	22.57
Wausau Papers Otis Mill	CP	Existing	11.285
BOC Kittery Load	CP	Existing	10.909
Hardwood Products Company	CP	Existing	0.397
Scarborough Sanitary District	CP	Existing	0.223
	CP Total		45.384
Eff Maine Residential Efficient Products	OP	Existing	24.1
CPLN ME OP	OP	Existing	2.382
	OP Total		26.482
Verso Paper Androscoggin	REAL_TIME	Existing	39.497
Real-Time Demand Response - ME	REAL_TIME	Existing	37.616
Real-Time Demand Response - ME	REAL_TIME	Existing	25.078
Real-Time Demand Response - ME	REAL_TIME	Existing	25.078
Real-Time Demand Response - ME	REAL_TIME	Existing	25.078
Real-Time Demand Response - ME	REAL_TIME	Existing	12.539
Real-Time Demand Response - ME	REAL_TIME	Existing	8.276
CPLN ME RT-DR	REAL_TIME	Existing	5.642
Real-Time Demand Response - ME	REAL_TIME	Existing	4.765
Cascades Auburn	REAL_TIME	Existing	4.288
Real-Time Demand Response – ME	REAL_TIME	Existing	2.006
Non-UI Territory DR / Curtailment, ME	REAL_TIME	New	0.552
Isaacson Lumber	REAL_TIME	Existing	0.014
	RT Total		190.429
Real-Time Emergency Generation - ME	RTEG	Existing	12.288
Real-Time Emergency Generation - ME	RTEG	Existing	7.147
Electricity Supply Load Response CNE	RTEG	Existing	4.389
Real-Time Emergency Generation - ME	RTEG	Existing	3.135
Madison Electric Works	RTEG	Existing	1.229
Jackson Laboratory	RTEG	Existing	1.204
Robbins Lumber Inc	RTEG	Existing	1.185
Lewiston Auburn Water	RTEG	Existing	0.45
Portland Water District	RTEG	Existing	0.376
Brunswick Sewer District	RTEG	Existing	0.153
	RTEG Total		31.556
	Grand Total		293.851

Note: CP = Critical Peak, OP = On-Peak, RTEG= Real Time Emergency Generation
Source: ISO NE, "Obligations FCA 2011-2012", December 29, 2008, available at http://www.iso-ne.com/markets/othrmkts_data/fcm/filings/fca2_monthly_obligation_%20including_zeros_v7.xls

Q. Are all of these resources, or a significant portion of them, considered by CMP in its transmission needs assessment (Exhibit I-1)?

A. No. The "Efficiency Maine Residential Efficient Products" resource is likely included as part of CMP's direct consideration of Efficiency Maine conservation programs. And while it is possible that some portion of the "Real Time Emergency Generation" entries consists of generation resources directly considered by CMP in their modeling, I have not seen direct evidence of this thus far in CMP's application or discovery request responses. Thus it appears that most of these resources are not considered in the Exhibit I-1 assessment.

Q. To clarify, even though there are currently committed demand response resources for future years in the Maine zone, CMP does not model all or a significant portion of these resources as available to reduce peak load in 2017 in their transmission needs assessment (Exhibit I-1)?

A. No, they do not. All consideration of demand response resources is done in the non-transmission assessment (Exhibit I-3); CMP does not attempt to find transmission solutions that first recognize the peak load reducing effect of demand response resources. While it is true that no ISO NE FCM demand resource commitments have yet to be attained for the year 2017, since the ISO NE FCM capacity auctions are held three years in advance, there is no particular reason to believe that these resources, or at least some subset of them, would not be available for 2017.

Q. Are there likely additional demand response resources in Maine that could be available to reduce peak load in 2017?

A. Yes. In an informational filing made by ISO NE to FERC on September 9, 2008, ISO NE indicated that a total of 485 MW of Maine-based demand response resources were qualified to participate in the auction.[35] Since 293 MW cleared at auction, an additional 192 MW could still be available as a potential demand response resource in Maine, even if not used as an ISO NE FCM resource. This is based solely on a market-based response to provide demand resources, separate from any other direct efforts CMP could make to arrange for reliability-based demand response resources whose use could be more limited than what ISO NE may otherwise require.

Q. Has CMP adequately and in a timely manner examined the availability of demand response potential at their largest industrial customer facilities?

A. No. In response to OPA-03-03 (d), CMP stated:

> Q. Explain the extent to which CMP has considered the potential for custom-arranged demand response contracts with any of these large pulp and paper customers for extreme peak periods.
>
> A. CMP has considered the potential for custom–arranged demand response contracts and expects to begin discussions to that end with the appropriate pulp and paper customers, as appropriate.

And at the technical conference on November 19, 2008 CMP's Paul Dumais followed up on the OPA-03-03 (d) discovery response and stated that CMP was effectively still in the early stages of investigating demand response options, as noted in the transcript:

> MR. FAGAN: Okay. Response -- I think it was letter D of 3-3, in your response you talked about considering the potential for customer ranged demand response contracts concerning pulp and paper customers. Could you give me a little bit more information on that as to where you might be with that, if you have any expectations of being able to arrange, customize demand response contracts with your largest pulp and paper customers?
>
> ***
>
> MR. DUMAIS: We've had some internal discussions just at the beginning of it. And we haven't had discussions with the customers yet, but it's something that we -- we know that we need to begin soon.
>
> MR. FAGAN: Okay, that's it more or less at this point?
>
> MR. DUMAIS: Yeah.
>
> MR. FAGAN: Okay. Do you have any sense of if there may be some potential there?

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[35] Available at http://www.iso-ne.com/regulatory/ferc/filings/2008/sep/er08-1513-000_09-09-08_fca_info_filing.pdf and http://www.iso-ne.com/markets/othrmkts_data/fcm/filings/attachments_for_info_filing.xls.

MR. DUMAIS: I think that there's some potential there. I think some of the issues that -- you know, that we're going to need to address have to do with demand response programs in ISO-New England that they may already be participating in and now that might interact with what we'd be asking them to do. We also need to define -- and this is some of the in-house discussions -- define what it is we'd be asking them to do because these would be for -- interruptions for transmission issues. You know, these customers are generally used to doing interruptions based on ISO programs."[36]

These responses indicate that one of the less expensive means of reducing peak period load for reliability purposes – demand response at large industrial facilities – was not sufficiently investigated as a means to reduce future peak load levels prior to proceeding with the transmission need modeling for the MPRP. CMP explicitly considers only the peak load reducing effect associated with projections of Efficiency Maine conservation programs, and does not attempt to explicitly incorporate reductions that could be obtained through efforts with their larger customers. Instead, CMP models its system and suggests transmission system upgrades before establishing the extent to which such load response could actually be achieved.

Q. What level of demand response resource is included in CMP's non-transmission assessment (Exhibit I-3)?

A. The NTA solution includes 188 MW of demand response resource by 2017, and 229 MW of demand response resource by 2027, as indicated in Table 15 below. I note that Exhibit I-3 indicates 179 MW of demand response resource is available by 2017[37], not 188 MW as the NTA modeling in EX-07-07 indicates.

[36] Transcript, page 146, lines 1-10.
[37] Exhibit I-3, page 23 (page 26 of 464).

Table 15. Demand Response Resources Included in the NTA Assessment

Year	Cumulative Demand Response, MW	Year	Cumulative Demand Response, MW
2008	98.4	2018	191.8
2009	108.1	2019	195.7
2010	117.7	2020	199.6
2011	127.5	2021	203.6
2012	137.3	2022	207.6
2013	147.3	2023	211.8
2014	157.3	2024	216.0
2015	167.5	2025	220.4
2016	177.7	2026	224.8
2017	188.1	2027	229.3

Source: Response to EX-07-07, Attachment 1, MPRP Scorecard Model v 10 – ME – NTA v2, "demand response" worksheet.

Q. What is the basis for the NTA Assessment use of these values for demand response?

A. The basis is the GDS potential study included as part of Exhibit I-3. That report states that GDS used "an engineering approach to estimate demand response potential"[38], essentially an end use and customer participation rate assessment. GDS states that "The assumed rate of customer participation in demand response programs is a best estimate of long term participation based on a review of other relevant studies and reports"[39]. They also state that it is a "best estimate based on relatively limited experience with demand response programs in Maine and nationally".[40]

Q. Does CMP, or GDS, take into account the experience seen with demand response resource participation in ISO NE's Forward Capacity Market auctions to date?

A. No, they do not. However, at the time of the GDS report (February 2008, and the Addendum in March, 2008) the results of the first ISO NE Forward Capacity

[38] Exhibit I-3, page 225 of 464.
[39] Exhibit I-3, Page 162 of 464.
[40] Exhibit I-3, page 223 of 464.

Market auction had just been announced (on February 13, 2008).[41] However, in November, 2007, ISO NE provided its first FCM auction informational filing to the FERC that indicated that significant demand response resources had qualified to participate in the auction.[42] Thus, it is reasonable to expect that at the time of the CMP filing, and even at the time of GDS's analysis of demand response potential, the indications from the ISO NE FCM auction informational filing could have been taken into account.

Q. If they were taken into account, how might the NTA Assessment have differed from CMP's file version?

A. I would expect that more demand response resources would have been considered as part of the potentially available resources, based on empirical information available from the market, rather than relying solely on the results of the engineering approach model.

Q. Has there been additional demand response potential information made available since the July 2008 filing of CMP's application?

A. Yes. The results of the second FCM auction (2011-2012 period) were available in December, 2008. And, additional qualified demand response resources did not clear in the 2011-2012 auction; 485 MW of Maine zone demand resources qualified to bid in the 2nd FCA auction, yet only 294 MW cleared. This means that almost 200 MW of demand resources may still be currently available for participation in Maine, and this is without any concerted effort on the part of CMP to secure demand response commitments for the purpose of reliable system operation in the future. This potential increase in demand response resource availability, through the FCM mechanism or through more traditional utility-based means of obtaining demand response, would likely lead to significant

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[41] ISO NE FCA #1 2010-2011 Results, February 13, 2008, available at http://www.iso-ne.com/markets/othrmkts_data/fcm/cal_results/fca_2010_2011_results.pdf

[42] Available at http://www.iso-ne.com/regulatory/ferc/filings/2008/mar/er08-633-000_03-03-08_fca_results_filing.pdf, November 6, 2007.

increases in Maine demand resources by 2017, well above CMP's modeled level of 188 MW.

Q. What level of demand response is considered in the Western Maine sub-area, a region with extensive large industrial load?

A. Exhibit I-3 indicates that only 19 MW of demand response is considered available by 2017. The total 90/10 load in Western Maine in 2017 is projected to be 447 MW[43], and three large paper and pulp mills with a gross base load of 289 MW are included in this total.[44]

Load Forecasting and Industrial Load in Planning Model

Q. Do you address CMP's load forecast in this testimony?

A. Yes. I note that the extraordinary economic conditions currently facing the nation and the region have the potential to dramatically reduce Maine load relative to what has been forecast in CMP's case.

I also note that economic conditions have led to ISO NE revising its load forecast for its 2009 Regional System Plan (RSP). The update, issued by ISO NE on January 21, 2009, indicates that its forecast of ISO NE region summer peak load (50/50) for 2010 (28,162 MW) is 793 MW lower (2.7% lower) than its 2008 RSP forecast of summer peak load (28, 955 MW). This represents a dramatic reduction in load forecast compared to values from the 2008 Regional System Plan for 2010. Table 16 below contains the relevant forecast information as published by ISO NE.

[43] Exhibit I-3, page 110 (page 113 of 464).
[44] Response to OPA-03-03 and CES-01-09 (location of pulp and paper companies).

Table 16. ISO NE Load Forecast Update

RSP09 Preliminary Short-run Forecast for 2009 and 2010 of ISO-NE Energy and 50/50 Seasonal Peaks Based on Economy.com Dec 2008 Forecast.

	RSP09	Annual % Change	RSP09-08	Adjustment to Trend MW	Revised RSP09	Annual % Change	RSP09-08	RSP08	Annual % Change
ENERGY (GWh)									
2007	134109							133720	
2008	131501	-1.94	-3499					135000	0.96
2009	131318	-0.14	-5222					136540	1.14
2010	131331	0.01	-6554					137885	0.99
50/50 SUMMER PEAK (MW)									
2008	27765		-205		27765		-205	27970	
2009	28066	1.08	-414	-190	27876	0.40	-604	28480	1.82
2010	28447	1.36	-508	-285	28162	1.03	-793	28955	1.67
50/50 WINTER PEAK (MW)									
2008/09	22130		-900					23030	
2009/10	22101	-0.13	-1219					23320	1.26
2010/11	22102	0.00	-1478					23580	1.11

2007 and 2008 energy are weather normal, 2008 summer peak is weather normal.

ISO new england RSP09 Forecast Update © 2009 ISO New England Inc. 13

Source: ISO NE.

Q. Did ISO NE release information on its forecast for Maine load?

A. No. I anticipate that such forecasts will be available in the coming months, and ultimately will be used in the annual CELT reports that are issued in April.

Q. What effect does this have on CMP's MPRP petition?

A. At a minimum, this information illustrates that it is likely that "year of need" for any required transmission facilities could be pushed out by a number of years. This development alone could require revised analyses to determine the way in which "need" is lessened by the forecast change. Practically speaking - given our recommendations to revisit planning criteria and to analyze "hybrid" transmission/ non-transmission alternatives – it means that CMP should incorporate updated load forecasts in any subsequent analyses.

Q. What other aspects of CMP's load forecast do you address in this testimony?

A. CMP states in its Needs Assessment (Exhibit I-1) that

> "Large industrial customers in CMP's service territory were assumed at contractual load limits for the 10-year 2017 analyses. This assumption adds approximately 200 MW to the previously identified New England load and CMP load forecast" (Exhibit I-1, page 22, page 30 of 573)

CMP also states in its Exhibit B-2 (Load Information) in the section "Adjustments for Industrial Customer" that

> "The next step was to adjust the forecast to reflect the planning assumptions appropriate to transmission reliability. As noted above, the base forecast was developed to project the most likely level of load. The MPRP, because it is a planning study for the purpose of ensuring system reliability at all times and not just under average conditions, needed to evaluate system performance under more extreme (but still plausible) scenarios. It is because of these differences that additional adjustments described below, had to be made to the peak load forecasts and bus load distributions used in the MPRP". (Exhibit B-2, page 6 of 9, page 9 of 53).

Based on Table 2 – Maximum Contracted Load Adjustments (Exhibit B-2, page 7 of 9, page 10 of 53), and based on the modeled loads reported in response to OPA-03-03 (c), it appears that the roughly 200 MW of "adjustment" comes from changes to industrial modeled loads.

Q. Should 2017 modeled system conditions increase base 90/10 load by 200 MW to reflect CMP's contention of a need to model such "extreme" conditions?

A. No. The 90/10 load forecast accounts for such extremes. What CMP has adjusted is the contracted load levels. They are essentially saying that they should account for additional load when considering a build out of the transmission system even though they do not have a contractual basis on which to forecast such load. This is not sufficient rationale to add 200 MW of load to the model, especially given the existence of substantial self-generation assets in the region.

Conclusions and Recommendations

Q. Please summarize your key conclusions.

A. As described in Mr. Lanzalotta's testimony, CMP has not demonstrated that transmission needs in 2012 or 2017 support the proposed scope of transmission investment contained in the MPRP transmission solution. CMP has not sufficiently analyzed potential hybrid combinations of transmission and non-transmission elements to meet any future reliability need. CMP has not demonstrated that their proposed MPRP transmission solution is more cost effective, from a Maine ratepayer perspective, than a non-transmission alternative solution.

Q. Please summarize your recommendations.

A. I recommend the following:

1. In conjunction with Mr. Lanzalotta I recommend that the Commission reject CMP's application for a CPCN for the MPRP application as currently proposed, and I recommend that planning criteria more reasonable than that used by CMP in this application be used to assess any future reliability need.

2. I recommend that CMP examine hybrid solutions for transmission system reliability needs that include existing elements such as the current Special Protection Systems, and that also include the full economic potential of elements with significant economic benefit such as incremental energy efficiency and demand response, and targeted NTA generation.

3. I recommend that CMP carefully analyze the potential for demand response resources given the extent of qualified demand response resources in Maine seen in the ISO NE FCM market qualification information and FCM auction results to date.

4. I recommend that any revised MPRP analyses more carefully assess forward capacity market obligations and costs to Maine customers than has been done in the current application, and in particular that the effect of NTA generation quantity on the price-setting dynamics of the FCM be investigated more thoroughly.

5. I recommend that non-transmission elements that can reduce peak load be considered in the transmission need modeling and not separately addressed as was done in the NTA Assessment.

6. Lastly, I recommend that any future analyses carefully incorporate revised load forecasts that account for the current economic downturn and its anticipated impact on future peak load.

Q. Does this conclude your testimony?

A. Yes.