STATE OF MAINE PUBLIC UTILITIES COMMISSION
Docket No. 2008-255

CENTRAL MAINE POWER COMPANY
and
PUBLIC SERICE 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")

FILING BY
GRIDSOLAR, LLC

REQUEST FOR CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE GRIDSOLAR TRANSMISSION RELIABILITY PROGRAM CONSISTING OF THE DEVELOPMENT (AT THE END AND FOR ADDITIONAL SPECIFIED RELIEF) OF UP TO 800 MW OF DISTRIBUTED SOLAR GENERATION AND ASSOCIATED INTERCONNECTION AND RELIABILITY FACILITIES ("GRIDSOLAR PROJECT")

SUPPLEMENTAL FILING

September 8, 2009

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I. OVERVIEW OF SUPPLEMENTAL FILING

Since we made our initial filing in this case, CMP has made a number of supplemental filings to its direct case filed on July 1, 2008 and provided additional materials in the form of responses to Data Requests and discussions at Technical Conferences. In this Supplemental Filing, we are updating our initial filing to reflect a number of changes, modifications and extensions. These include (i) updating peak energy forecasts to reflect the deterioration of the U.S. economy and the impact this has had on the amount of electricity used in New England and Maine, (ii) reflecting the fact that pricing for solar PV systems has fallen precipitously, even faster than was forecasted less than a year ago, and that new cost projections indicate that this trend is likely to continue over the foreseeable future, and (iii) incorporating various refinements to the GridSolar Project financial model.

We have also taken this opportunity to add a component comparing the MPRP and the GridSolar Project on total costs and on job creation benefits over the period 2010 through 2020. Each of these comparisons is based on a projected build out of the GridSolar Project that represents our best estimate of how much distributed solar generation will need to be installed to meet future load growth in order to ensure that the CMP bulk transmission system meets NERC reliability standards. Incorporating a build out scenario is critical to any comparison of the costs of the MPRP and GridSolar Projects, since the costs per MW of the GridSolar Project are falling significantly over the build out period. If the pace of the build out is slowed for any reason, including overall economic conditions and slower load growth, the costs of meeting the NERC reliability standards under the GridSolar Project will fall. This has obvious implications to ratepayers and therefore should be a critical factor in any evaluation of the two alternatives by this Commission.

II. MODIFICATIONS AND ADJUSTMENTS TO SUPPORTING DOCUMENTATION IN INITIAL PETITION FILED IN THIS CASE

A. Discussion of relationship between DC ratings of solar modules, AC capacity requirements and annual capacity factor

The standard for rating the capacity of solar PV systems is to use DC output. Because there are inverter losses in converting DC to AC for interconnection to the electric grid, the nameplate rating of solar PV systems must be reduced to reflect these conversion losses (or alternatively, more capacity must be installed to offset these losses.) We have adjusted our modeling to incorporate 5% inverter and transformer losses. This adjustment has two impacts – (i) it increases the cost of installed PV systems measured as AC capacity by about 5% and (ii) it increases the annual capacity factor, again, when measured based on AC capacity.

This second impact is counter-intuitive, but stems from the way in which output of these systems in generally reported. The standard is to report energy output in terms of kWh/KW. Since the KW term is usually reported as DC capacity, derating this by inverter losses to obtain AC capacity has the effect of lowering the denominator, thereby increasing the annual capacity factor. Of course, the amount of energy produced does not change. We have revised our annual capacity factor for single-axis tracking systems based on incorporating these losses and additional solar radiation modeling results from 20% (AC) in our Petition to 18.42% (AC).[1]

B. Capacity Credits for GridSolar Project

[1] We note that distributed generation will have less AC electrical losses than energy brought long distances at high voltages over the MPRP lines, even with the loss reductions the MPRP will produce. We are not able to compute these loss savings, but expect them to be considerably higher than those CMP has identified with the MPRP. We further understand that the Commission has taken notice of them in prior cases. Specifically, in exempting Maine generation that is not interconnected to the PTF from LNS charges, our understanding is that the Commission identified the lower line losses associated with this generation as one factor in its decision.

In our Petition, we modeled the capacity credits available as equal to 100% of the installed distributed solar generation nameplate rating (AC) under the assumption that the solar units would be backed up with either generation or demand response and would thus be able to deliver 100% of nameplate. While this assumption is correct, it also understates the amount of capacity actually available.

We have revised this assumption by focusing on the different types of capacity included in the GridSolar Project and their different characteristics vis a vis the capacity market in NEPOOL. These different characteristics will mean that each type of capacity will qualify for the capacity market, but the amount of capacity that can be delivered may be different from the nameplate rating of the units. We describe each of these below, along with the relative capacities assigned to each based on 1 MW of installed distributed solar generation:

- Solar Generation (1 MW) – Under ISO-NE rules, solar generation is an "intermittent resource", and its capacity is computed based on a complicated formula designed to capture the actual performance capabilities of the unit. We have applied this formula for a typical GridSolar Project distributed solar generation facility based on our standard solar radiation year – 2004. The modeling resulted in a computed capacity value of 65% of the AC nameplate rating of the solar unit.
- Back-up Natural Gas/Propane Generators (0.3 MW) – These units are treated for capacity purposes the same way typical fossil fuel units are treated, which is based on the EFORd measure. We anticipate bidding these units into the energy market each day at a price that reflects the high marginal operating costs of the units. Accordingly, we do not expect them to run in the energy market very often, and rarely if ever during an hour when they are not providing capacity to support the

CMP bulk power transmission system. Based on this, we have assigned these units a capacity rating equal to 100% of their nameplate ratings.

- Demand Response (0.3 MW) – These units will qualify for capacity under whatever load response program ISO-NE has in place at the time. Based on the performance characteristics of demand response to date, we expect that these units will perform at or above their "nameplate ratings". As a result, we have assigned these units a capacity rating equal to 100% of their nameplate ratings.

The weighted average is then computed as (1 MW * 65%) + (0.3 MW * 100%) + (0.3 MW * 100%) = 1.25 MW of capacity credit for each 1 MW of distributed solar generation installed.

C. Treatment of the Investment Tax Credit and accelerated depreciation

Our Petition modeled the Investment Tax Credit (ITC) as a 30% tax credit against taxable income with a carry forward provision that allows unused credit to apply against future tax obligations. The modeling also gave preferential depreciation treatment to the distributed solar generation investments by applying a MACRS depreciation schedule. Each of these items has been revised in our Supplemental Filing.

The effect of the first of these provisions is very significant. Under current federal law, qualified renewable generators may elect to have the value of the ITC paid upfront in the form of a cash grant from the U.S. Treasury. The opportunity to bring the full value of the 30% ITC to the present through a cash grant represents a very significant financial savings for GridSolar and therefore for ratepayers. The cash grant more than doubles the after-tax return on shareholder equity, all other things being equal. What this means is that GridSolar can achieve a target after-tax return on equity, while charging CMP for grid reliability at 70% of CMP's avoided costs and providing 100% of the energy generated by the distributed solar generation to Maine customers for free for 20 years. This is not magic. This result stems from three factors – (i) the capital intensive nature of the GridSolar Project, the size of the cash grant available from the U.S. Treasury and (iii) the very, very high cost of the MPRP relative to the incremental load growth it will support.

D. Back-up generation

In our Petition we modeled the financial impacts of the back-up generation requirement as if 100% of the capacity were being provided by newly installed natural gas or propane generators at the rate of 750 kW of capacity for each 1 MW of distributed solar generation installed. Based on further modeling efforts, we are adjusting these values as discussed below:

1. Capacity Requirements

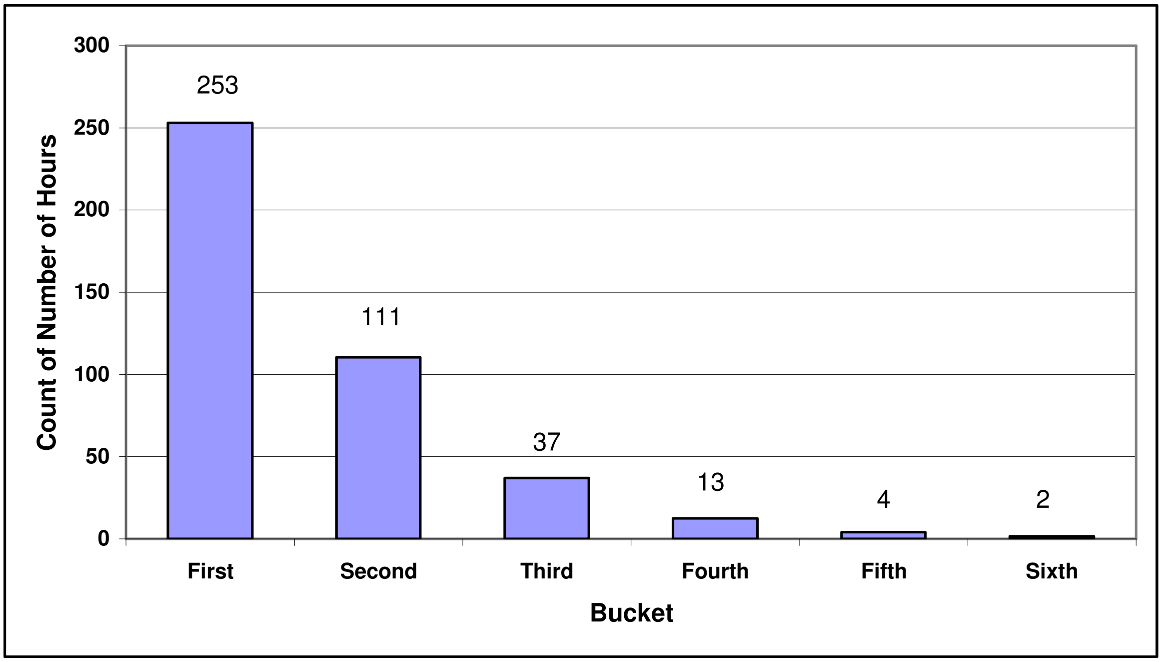
The 75% back-up requirement (750 kW per 1,000 kW of distributed solar generation) was set in our Petition very conservatively and based in part upon measured solar radiation at a single point measure in our initial modeling in Maine over a two-year period, 2004 – 2005. When we expanded the number of measured solar radiation points, we found that the number and intensity of shortfall events is reduced, i.e., the correlation of high load events and low solar radiation is greater for the single point than a distributed universe of solar generation. By looking at multiple locations, we have developed a better measure of the expected capacity of the distributed solar generation facilities when required to meet peak load conditions on the CMP bulk power system. This reduced the back-up requirement to approximately 65% or 650 kW for each 1,000 kW of distributed solar generation installed.

2. Resource Mix

The second modification we have made in this Supplemental Filing is to adjust the back-up capacity mix to reflect a more optimum mix of capacity resources for the load and generation conditions when these resources need to be called upon. We looked at each hour in 2017[2] when loads on the CMP bulk power system are projected to be above the critical load level, on the one hand, and where this excess load cannot be met by distributed solar generation, on the other hand. There are an estimated 253 individual hours when this condition prevailed, ranging from a shortfall of 1 MW to a shortfall of 401 MW.

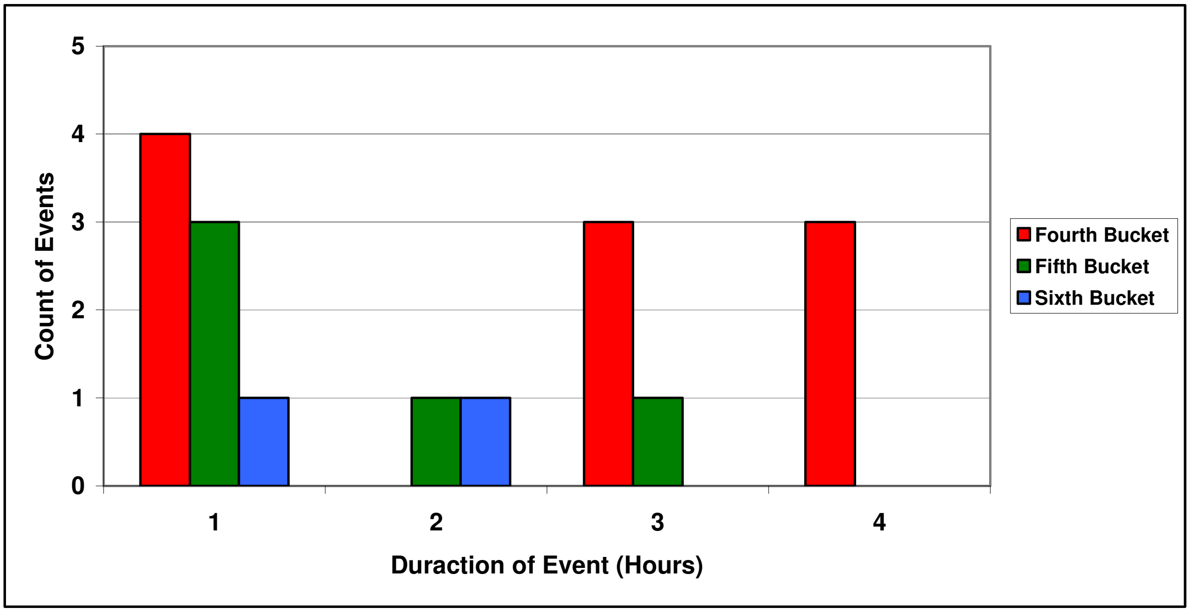
We then divided each of these hours into strata of 75 MW slices, which we refer to as "buckets". Using this terminology, an hour in which the shortfall is 350 MW, for example, would be one in which Bucket 1, Bucket 2, Bucket 3, and Bucket 4 would be "full", and Bucket 5 would be partially full at 50 MW. The table below provides a frequency distribution of the shortfall hours. This table represents a cumulative dispatch order – all of Bucket 1 is called before any of Bucket 2, all of Bucket 2 before any of Bucket 3 and so on. In addition, once Bucket 1 resources are called they continue to run until the shortfall event is over – Bucket 1 resources are supplemented by Bucket 2 resources, not replaced by them. Bucket 1 and 2 will continue to operate once Bucket 3 is called and so forth as each succeeding bucket is called. The table shows that there are relatively few hours in which we need to call upon back-up resources in Buckets 4, 5 and 6 (the Demand Response Buckets) – in fact, there are only 13 such hours over the course of the year. Working backward, we may need to call on up to 150 MW of demand response as much as 4 times a year and up to 75 MW as much as 13 times a year – however, in these latter two situations we anticipate rotating calls among the various customers providing this service to avoid placing too great a burden on these customers.

[2] The load curve for 2017 has been modified to be consistent with the revised lower peak load levels discussed elsewhere in this filing.



We next focused on the hours that fall into Buckets 4, 5 and 6 to determine how often such hours occur successively – that is, the duration of each event. Not surprisingly, many of these events are of one hour duration. The chart below shows the frequency of the durations of these events. The duration of an event is shown on the X-axis and the frequency of that event duration is shown on the Y-axis. Thus, for example, there were 4 events that fell into Bucket 4 (red bars) that were 1 hour in duration, no such events of 2 hours in duration, and 3 such events that were 3 hours and 4 hours in duration.

Notice that the event of longest duration that falls into Buckets 4, 5 or 6 is 4, meaning that the longest duration that a back-up demand response resource would have to be active to satisfy all of the Bucket 4, 5 and 6 requirements is 4 hours. It is this analysis that confirms our prior assertions that the back-up requirements for these Buckets are best suited to be met by demand response. The frequency of such events over the course of the year and an event's maximum duration will not place too onerous a burden on customers or lead to customer "fatigue". Since these Buckets account for about 50% of the maximum back-up capacity required, we anticipate meeting 50% of our maximum back-up obligation using demand response resources.



While Buckets 4-6 are met by both Demand Response and engine generation as described above, the remaining 50% - Buckets 1, 2 and 3 – will be met using natural gas and propane engine-generators exclusively. Not all of this capacity, however, must be new capacity. As we discuss in some detail in our Petition, GridSolar intends to install back-up engines at host facilities that can utilize the capacity for those hours when the electric grid is down. Based on our knowledge of commercial and institutional customers in Maine, some of these host facilities already have on-site back-up generators that provide some but not 100% redundancy for these facilities. GridSolar will utilize these generators in conjunction with the new ones installed to meet its back-up obligations. We estimate that the ratio of new to existing back-up generators will be about 4 to 1, i.e., 20% of the back-up generators in the GridSolar Project will be existing generators. GridSolar believes that these existing generators will be available at lower cost than for new generation.

As we noted in our Petition, the number of hours these back-up generators actually have to operate and the energy they need to generate is very small. The prior chart indicates that we need up to 75 MW for 253 hours during the year, up to 150 MW for 111 hours of the year and up to 225 MW for 37 hours of the year. We note also that the longest duration of any event is 12 hours, and that only 34 of all such events are of 5 hours duration or longer. The total number of MWhs that these units will generate across all 253 hours of shortfall is approximately 40,000 MWhs.

3. Treatment of Demand Response

A third modification we have made in our Supplemental Filing is to separate out the financial treatment of demand response from back-up generation. As we have informed the Commission and the parties in this case, GridSolar has entered into an agreement with EnerNOC, Inc. to provide load response and back-up generation services. The amount that GridSolar pays to EnerNOC for these services will be offset to some extent by the payments EnerNOC receives from load that is participating in the ISO-NE capacity demand response programs. In turn, EnerNOC will split the fees it receives from GridSolar with its customers. Because these customers will be expected to interrupt load in response to system-wide emergencies under the ISO-NE plan and also in response to GridSolar obligations to maintain reliability of the CMP bulk power system, we anticipate that we will have to pay these customers a premium over what they would otherwise receive from the ISO-NE programs. It should be noted, however, that the incremental costs of the equipment, communications, load monitoring and generation dispatch operations to these customers participating in the GridSolar Project in addition to the ISO-NE programs are minimal.

E. Miscellaneous Adjustments

1. Acres per MW of installed distributed solar generation

We have reduced the number of acres per MW of installed distributed solar generation from 12.5 to 8.5 based on further research. This has a negligible impact on the financial status of the GridSolar Project as land acquisition costs represent a very small percent of the total cost of the overall Project.

2. REC Prices for Solar Generation

We believe that our estimates of the value of solar renewable energy certificates or "SRECs" in our Petition are too low based on recent developments in the industry. The values we used in our Petition were equivalent to our estimates of the future value of Class 1 RECs, generally, in the region. We did not distinguish between Class 1 RECs and SRECs.

Since filing our Petition, a number of things have happened that lead us to believe that SRECs will be more valuable than other Class 1 RECs in New England. These include the enactment of a new feed-in tariff (or FIT) in Vermont that establishes a baseline price of $300.00 per MWh for 20 years for solar energy for facilities up to 2.2 MW in capacity, and discussion underway in Massachusetts to create a separate RPS carve out for solar energy and Alternative Compliance Penalties of about $600 per MWh for periods up to 15 years.

Based on these and other events across the U.S., we have increased the value of SRECs used in the financial modeling.

F. Falling Solar Module Costs

A very important component of the modeling we did in the Petition was to fix the first year of the financial proforma at 2011, despite the fact that the GridSolar Project involves the build-out of distributed solar generation over a ten-year (and perhaps longer) period. This is of only minor consequence when cost structures are relatively stable; however, in situations in which costs are increasing or falling rapidly, fixing prices as of the starting date will distort the final costs of a project.

As we have noted repeatedly, the costs of solar PV generation have been falling precipitously and are projected to continue to fall along very steep cost trajectories. This means that distributed solar generation facilities installed in 2012 are likely to have lower initial costs than those installed in 2011, and these lower costs may lead to lower life-cycle costs, even when measured in nominal dollars. Further, facilities installed in 2015, 2018 and 2020 are likely to have lower costs still.

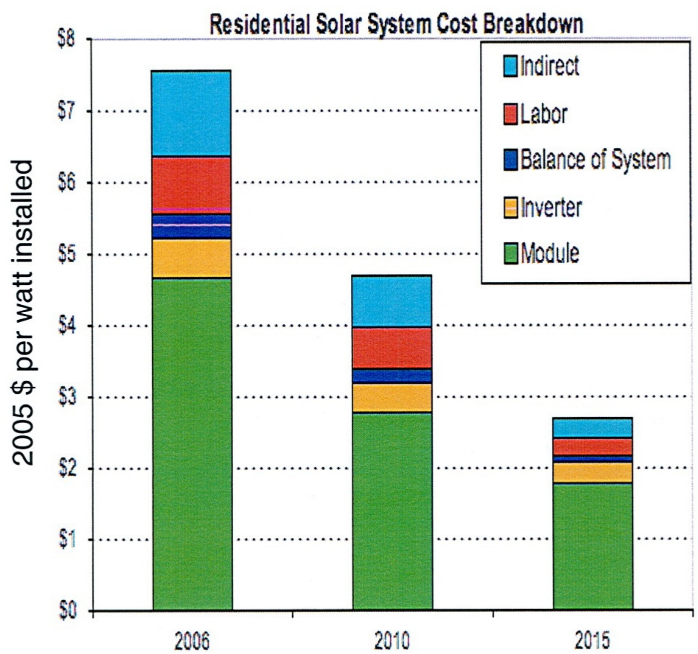
We have revised our financial pro forma to include the impact of falling solar PV costs, using cost trajectories provided by the U.S. Department of Energy. The DOE cost trajectories are shown in the chart below. This chart is in 2005 dollars. This chart is very helpful, as it provides projected costs broken down by cost component for commercial installations.

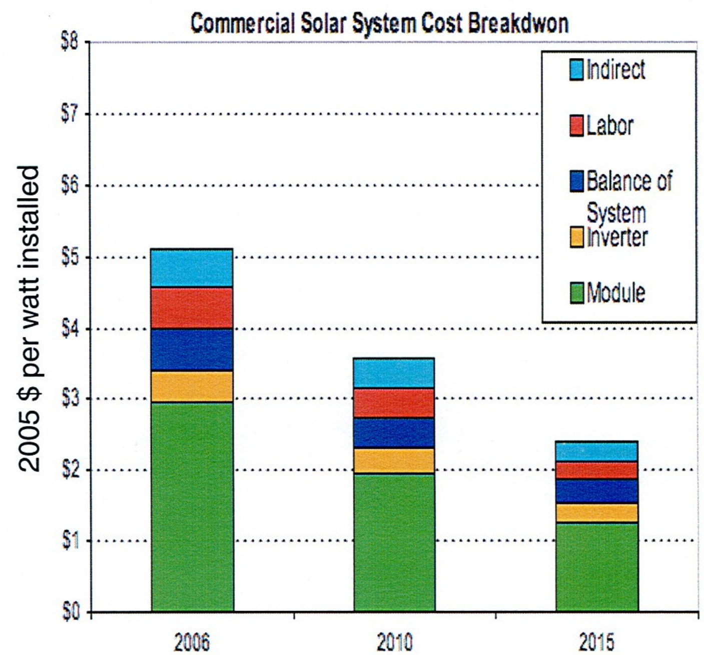
We have adjusted the figures for 2010 and 2015 by inflation at an average rate of 3% per year, and interpolated the intervening years. We have extended this cost trajectory out to 2020 by assuming that the reduction in real costs from 2015 to 2020 is only 50% as large as the reduction forecasted between 2010 and 2015. The results of this analysis are shown in the chart and accompanying table. This table shows the installed cost of commercial installations for 2009 to be $4.28 per Watt in nominal dollars, falling to $3.80 per Watt in 2011. These costs are essentially identical to the per watt installed costs we used in our Petition for facilities installed in 2011.

We then used these installed costs per Watt and the build-out capacity figures to compute a weighted average installed cost per Watt for the period 2011 through 2020. This figure is $2.92 per Watt for the distributed solar generation and $3.12 per Watt inclusive of the back-up generation units.[3] At this installed cost per Watt and assuming that GridSolar is paid 100% of the avoided transmission costs for providing grid reliability services (estimated at approximately $2,000 per kW), GridSolar can offer 100% of the output of the solar generation to ratepayers for free. Ratepayers will be able to capture 100% of the falling cost curve for solar power, something they will not be able to do without the GridSolar Project. If the upfront U.S. Treasury grant is available throughout this period, the economic value to ratepayers is even higher.

[3] For this purpose, we inflated the 2011 back-up generation capital costs by 3% per year.

But, the module is not all of the cost - DOE SAI industry partner installed system cost projections





- Note the high level of indirect and labor costs - these are driven by regulatory, educational and financing hurdles (non-R&D).

Established solar manufacturers are realizing cost reductions across the value chain and will reduce installed system cost by approximately 50% by 2015

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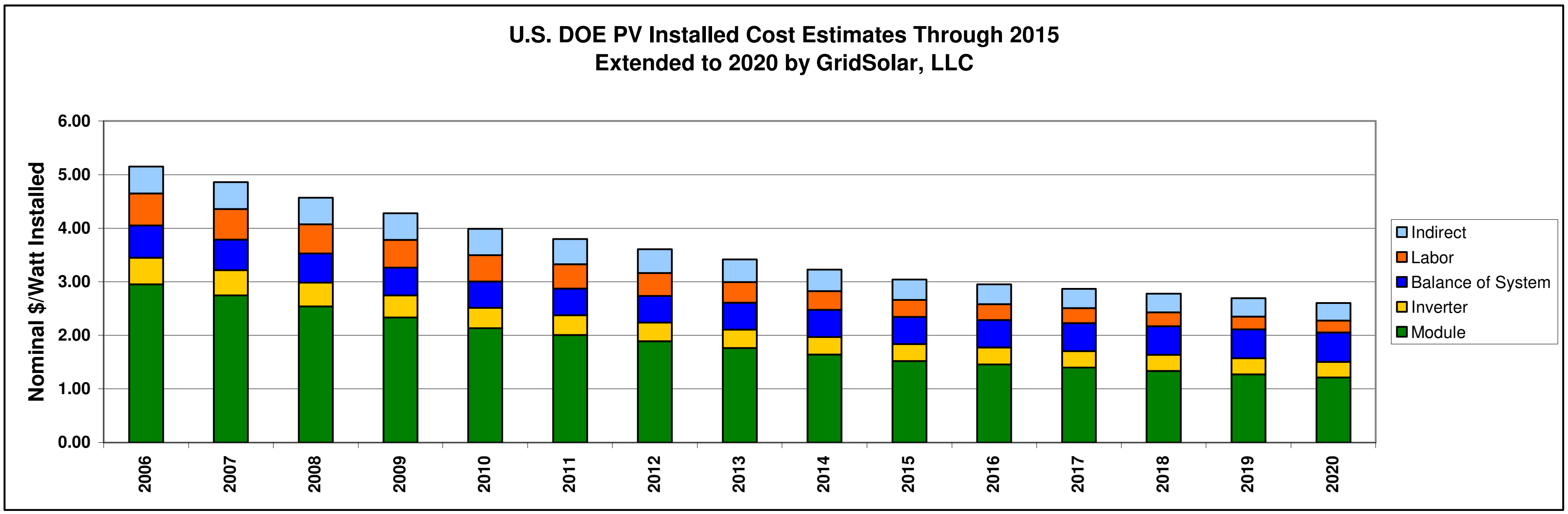
Projected Cost Trajectory for Components of Solar PV Systems - Commercial Applications

		2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Module		2.95	2.75	2.54	2.34	2.13	2.01	1.89	1.76	1.64	1.52	1.46	1.40	1.33	1.27	1.21
Inverter		0.50	0.47	0.44	0.41	0.38	0.37	0.36	0.34	0.33	0.32	0.31	0.31	0.30	0.30	0.29
Balance of System		0.60	0.57	0.55	0.52	0.49	0.49	0.50	0.50	0.50	0.51	0.52	0.52	0.53	0.54	0.55
Labor		0.60	0.57	0.55	0.52	0.49	0.46	0.42	0.39	0.35	0.32	0.30	0.28	0.26	0.24	0.22
Indirect		0.50	0.50	0.50	0.49	0.49	0.47	0.45	0.42	0.40	0.38	0.37	0.36	0.35	0.34	0.33
Total PV	$/Watt	5.15	4.86	4.57	4.28	3.99	3.80	3.61	3.42	3.23	3.04	2.95	2.87	2.78	2.69	2.61



III. COMPARISON OF COSTS AND JOB CREATION BENEFITS OF GRIDSOLAR PROJECT AND MPRP

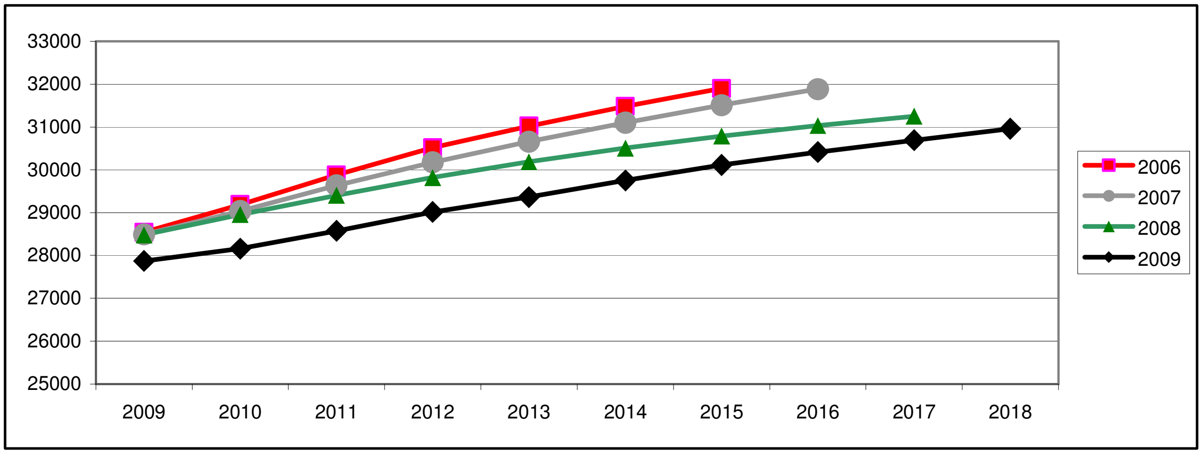
A. Revised ISO-NE Load Forecasts – RSP 2009

Our initial Petition was based on load forecasts developed by CMP in late 2006. These were prepared to support the needs assessment initiated by CMP, which led ultimately to the identification of the MPRP. Since these forecasts were prepared, economic conditions in the country and in Maine have deteriorated significantly, and projections for future economic growth and consequent electric load growth have been reduced.

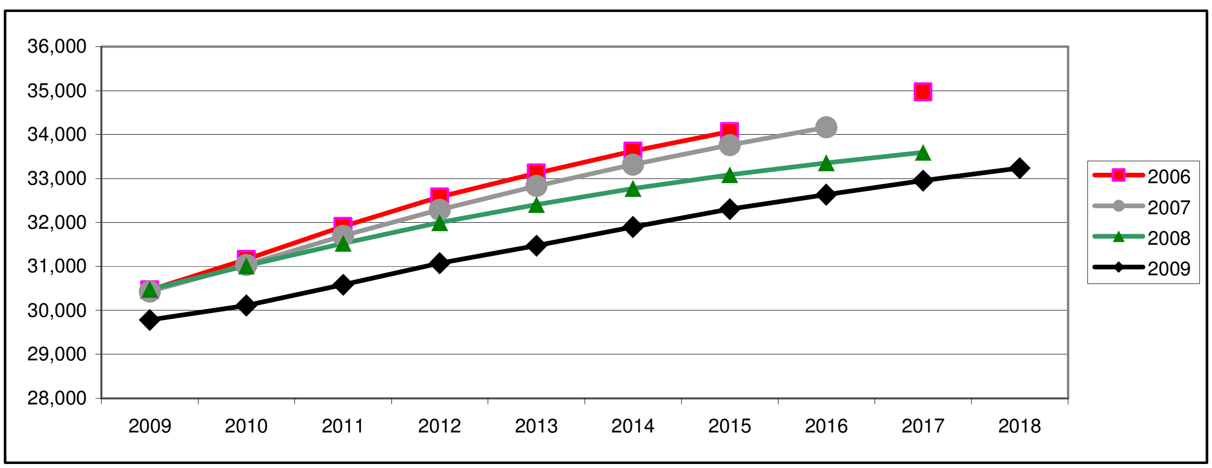
The chart below shows how ISO-NE load forecasts have been scaled back over the past 4 years. As this chart shows, ISO-NE has revised its forecasts downward each year since 2006 as actual ISO-NE peak loads have consistently fallen short of forecasts. This is true for both the 50/50 and 90/10 scenarios. The reduction in load forecasts for the 90/10 scenario has a direct impact on the MPRP. The 2017 forecast used by CMP in its needs assessment was 34,970 MW, shown as the highest point on the bottom chart. This figure is 2,000 MW above the current ISO-NE forecast for this same period under the same 90/10 scenario. This represents a difference for Maine of about 170 MW, assuming the reduction is spread across the region in rough proportion to energy use. [We note that one of the underlying assumption of the MPRP was that Maine load shape would move toward a more typical New England load shape over this time period. The slowing of the load growth projections is also likely to slow the change in shape as well as a simple consequence of a less dynamic environment. We have not attempted to model the impacts of this likely path.] More significantly, the level of load in 2012 identified in the CMP needs assessment as the year of need is not achieved until 2016 under the revised 2009 load forecast.

CELT FORECAST - NEPOOL SUMMER PEAK LOADS

Report Year	Forecasted Loads - 50/50 Scenario 2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
2006	28,540	29,185	29,885	30,515	31,020	31,480	31,895			
2007	28,495	29,035	29,635	30,175	30,660	31,100	31,510	31,885		
2008	28,480	28,955	29,405	29,820	30,190	30,510	30,790	31,035	31,250	
2009	27,875	28,160	28,575	29,020	29,365	29,750	30,115	30,415	30,695	30,960



Report Year	Forecasted Loads - 90/10 Scenario 2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
2006	30,465	31,160	31,910	32,580	33,125	33,620	34,065		34,970	
2007	30,430	31,035	31,695	32,290	32,830	33,315	33,765	34,170		
2008	30,475	31,015	31,525	31,995	32,410	32,775	33,085	33,360	33,595	
2009	29,780	30,110	30,580	31,075	31,470	31,900	32,305	32,635	32,950	33,235



Note: Value of 34,970 MW in 90/10 Scenario for 2006 CELT Report for 2017 is taken from CMP Needs Assessment.

The following chart (and accompanying table) below show the ISO-NE load forecast for the CMP Service Territory in its 2009 Regional System Plan ("RSP"). This chart shows summer and winter peak loads under both the 50/50 and 90/10 scenarios for CMP for the Southern Maine and Central Maine portions of its service territory. We have also shown the 90/10 forecast for 2017 as reported by CMP in its needs assessment.

The ISO-NE forecasts are important in this case for three reasons. First, as noted above, the level of peak loads are used by CMP in its needs assessment to determine the "Year of Need" for each transmission upgrades. As the load forecasts are lowered, all other things being equal, the year of need will get pushed further into the future. By doing so the costs of any transmission upgrades to current ratepayers are reduced, as is their exposure to risks. If we use an average carrying cost for transmission investments of 15% of invested dollars, each year of carrying $1.5 billion represents a cost to ratepayers of about $225 million. A four-year delay, then, represents a deferral of almost $1 billion of ratepayer costs.

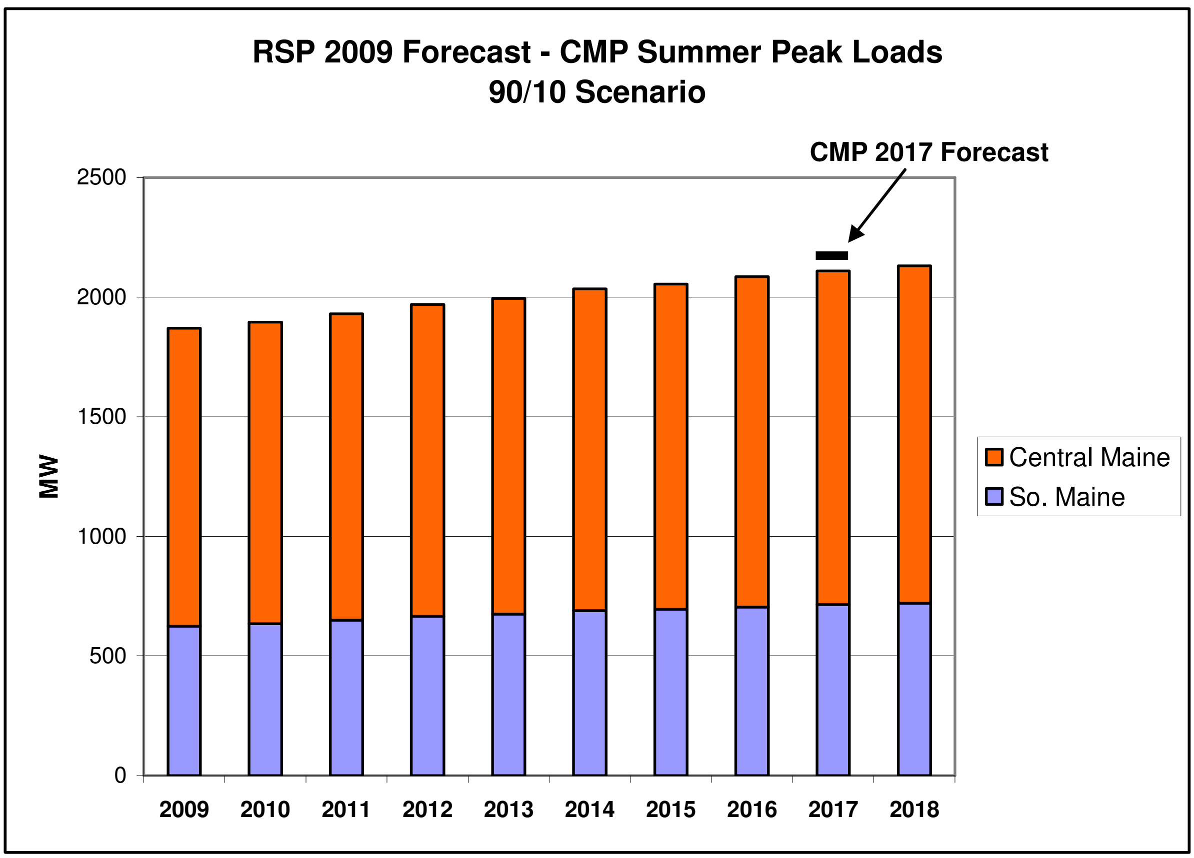
A more important consideration, however, relates to the lumpiness of transmission investment and the need to build significant excess capacity in anticipation of load growth. The longer it takes for the load to grow, the more all ratepayers will pay for excess capacity, effectively raising the price of the capacity that is actually being used.

Finally, the longer it takes for load to grow and utilize the transmission investment, the more likely it is that some portion of that investment will become obsolete and therefore stranded by future events. This is true of any capital investment, whether it is an expansion of a public school, the construction of a railroad line, or the building out of transmission lines. If we could predict the future perfectly, we could make capital investments that precisely match the need. Because we cannot make perfect predictions, we know that we will have a mismatch between investment and needs. Transmission investments present an extreme case of risk of stranded cost, because the vast majority of the investment is required upfront and the reliability hazard of a shortfall is very high. The convergence of these two factors leads to very large transmission investments long in advance of the time of actual need. Historically, investments in transmission in advance of when they are actually "used and useful" have presented only a time value of money loss potential, because "it all got used eventually." In today's increasingly dynamic environment, where alternatives to transmission are increasing rapidly, this historic axiom is no longer a certainty. Indeed, overinvestment in transmission will lead to higher costs for grid-based electricity that will add impetus to the search for alternatives to these increasing costs. This feedback effect has had very powerful consequences in the past for network services as railroad development led to a stranding of dollars invested in canals; highway development led to railway abandonment; wireless telephony is creating significant exposure to wire-based carriers and the internet is resulting in a substantial reduction in the volume of mail, leading to major cost increases for the U.S. Postal System and potential reductions in service.

2009 CELT & RSP Forecast Detail: CMP Service Territory

	Reference Weather Peaks (MW) 50% chance of being exceeded		Extreme Weather Peaks (MW) 10% chance of being exceeded		
	Summer	Following Winter	Summer	Following Winter	Energy (GWH)
2009	1750	1600	1870	1650	9860
2010	1770	1600	1895	1650	9855
2011	1800	1600	1930	1650	9930
2012	1830	1605	1970	1655	10050
2013	1850	1605	1995	1655	10085
2014	1880	1605	2035	1655	10185
2015	1910	1610	2055	1655	10290
2016	1925	1610	2085	1660	10375
2017	1950	1610	2110	1660	10485
2018	1970	1610	2130	1660	10590
CAGR	1.30%	0.10%	1.46%	0.07%	0.80%

CMP MPRP Load Forecast for 2017			2200		



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B. Build Out Schedules for MPRP and GridSolar Project

We have compared the build out schedules for the MPRP with what these revised RSP 2009 load forecasts require under the GridSolar Project. First, with respect to the MPRP, we have used the information provided by CMP in its filings in this case to develop the dollar spending by year under the MPRP, assuming that it is approved in full early in 2010.[4] The results of this are shown by calendar year in the table below:

MPRP - Annual Capital Spending

2010	$15,500,000
2011	$94,184,028
2012	$481,270,032
2013	$543,369,391
2014	$377,771,100
2015	$38,750,000
	$1,550,844,551

Build out of the GridSolar Project will depend on what level of loads are required to ensure that the existing CMP bulk transmission system meets NERC reliability standards and how rapidly peak loads grow over the next 10 years.[5] To do this analysis, we have used the results of certain sensitivity analyses performed by CMP with respect to the load reductions from the 1,600 MW level necessary to ensure that its bulk transmission system meets NERC reliability standards.[6] The results of these analyses indicates that the current transmission system meets

[4] See Updated Testimony of Eric N. Stinneford and Paul A. Dumais "Economic Impacts & Benefits", March 9, 2009, Attachment ENS/PAD-3, Page 8 of 9.

[5] Build out in this context refers to the distributed generation component of the GridSolar Project. The metering and communication systems component of the Project will need to be installed up-front to enable GridSolar to monitor loadings on each component of the CMP transmission system as these loadings will determine the actual build oout of the distributed generation facilities.

[6] This information was provided to the parties on September 1, 2009 in a confidential document titled "MPRP – GridSolar Data Request for NTA Threshold Load Levels at 1600 MW CMP Load".

voltage and thermal reliability criteria at load levels of approximately 1,500 MW for those generation dispatch cases consistent with the Staff's modeling conditions. This level is a full 100 MW below the base case used in the Staff Analysis and about 250 MW below what CMP used in its needs assessment as "current" peak loads on the system.

Second, we have assumed that peak loads grow according to the RSP 2009 peak load forecast discussed earlier through 2018 and then at 1.5% in each of the next two years. The 1.5% is the average forecasted growth rate and slightly higher than the CAGR for the same period.

Finally, we have assumed that the GridSolar Project will meet the reliability requirements in the year 2016, the same year that the MPRP is scheduled to be fully completed. These assumptions mean that the GridSolar Project will need to have 585 MW of solar installed by the end of 2015 – computed as the 2015, 90/10 peak load forecast of 2,085 MW less the critical load level of 1,500 MW, as shown in the table – GridSolar Project Build-Out.

This table includes a couple of other items of note. First, we show both AC and DC capacity. The standard capacity measure in the solar industry is a DC nameplate rating. We have used a 5% inverter and transformer loss to convert to delivered AC. Second, the rate of build out prior to 2016 is, to some degree, discretionary. We have modeled the numbers included in the table as representative of how rapidly GridSolar will develop distributed solar generation. These numbers are not reflective in any manner of capability limitations or constraints related to the ability to develop the GridSolar Project. Finally, as we have discussed throughout this case, GridSolar will install solar generation only as required due to increases in loadings on the CMP bulk transmission system. This means that the actual build out, including the target level of 585 MW by the end of 2015, will be revised over time based on economic and electrical conditions in the CMP service territory. As we have noted elsewhere, since the price of distributed solar generation is projected to fall considerably over the next 10 years, the cost of the GridSolar Project will fall if peak load growth does not reach the levels included in the RSP 2009 load forecast.

GridSolar Project Build-Out

	Growth Rate	RSP 2009 Peak Load Forecast MW (AC)	Annual Required MW (AC)	Cumulative Required MW (AC)	Annual Required MW (DC)	Cumulative Required MW (DC)
2009	0.0%	1,870		-		
2010	1.3%	1,895	15	15	16	16
2011	1.8%	1,930	30	45	32	47
2012	2.1%	1,970	70	115	74	121
2013	1.3%	1,995	90	205	95	216
2014	2.0%	2,035	110	315	116	332
2015	1.0%	2,055	130	445	137	468
2016	1.5%	2,085	140	585	147	616
2017	1.2%	2,110	25	610	26	642
2018	0.9%	2,130	20	630	21	663
2019	1.5%	2,161	31	661	33	696
2020	1.5%	2,193	32	693	33	729

CMP Critical Load Level	MW (AC)	1,500
Inverter Loss Factor	%	5.0%

C. Net Present Value Analysis of costs to ratepayers

We have used the build-out scenarios for MPRP and the GridSolar Project to compute the costs to ratepayers under each option. The results of this analysis are shown in the table titled "Ratepayer Costs – MPRP vs. GridSolar" and in the accompanying chart.

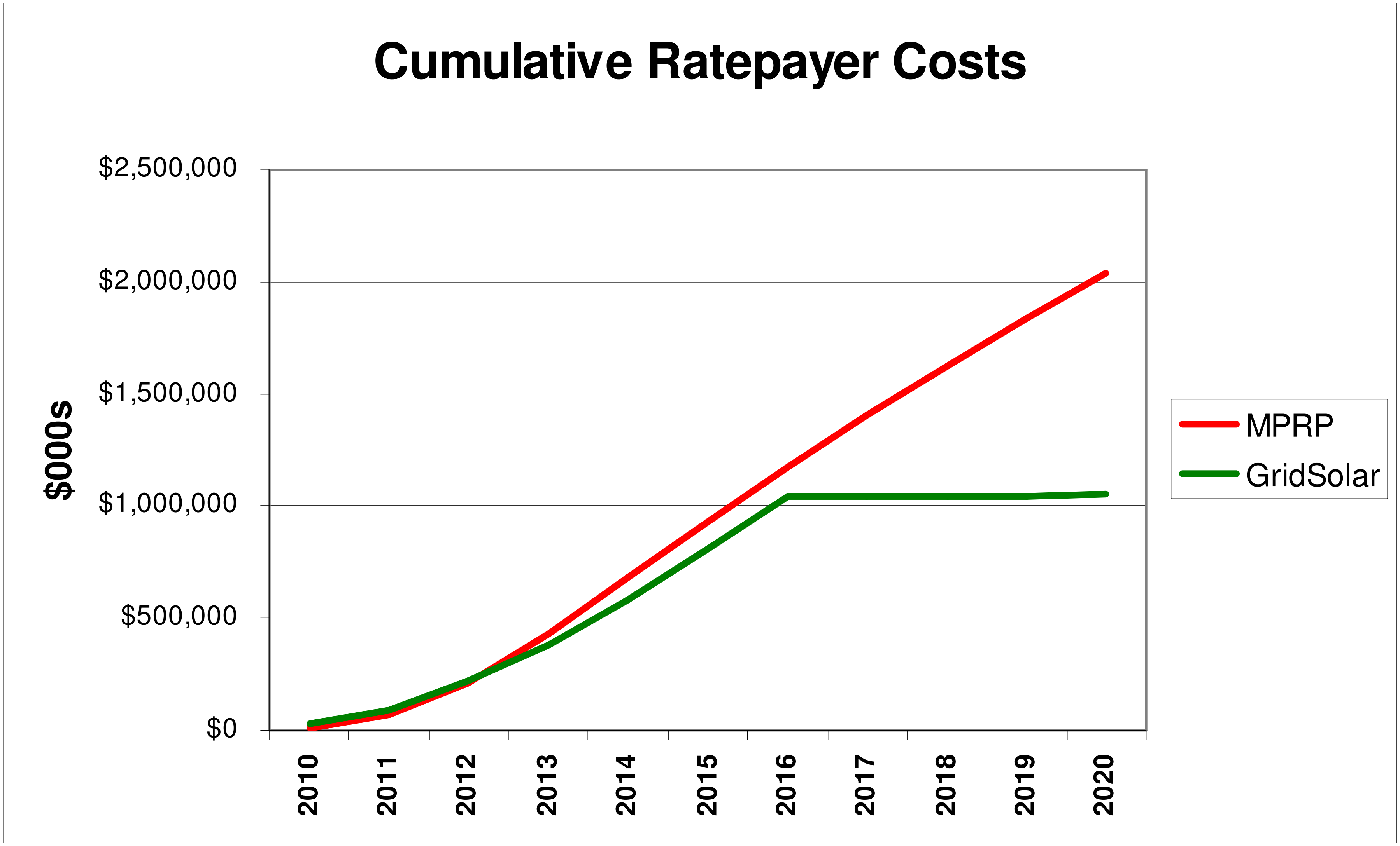
The first section of the table shows the projected capital expenditures by CMP under the full build out of the MPRP, as well as the annual carrying costs of the MPRP. The latter figures are taken directly from, Updated Testimony of Eric N. Stinneford and Paul A. Dumais

"Economic Impacts & Benefits", March 9, 2009, Attachment ENS/PAD-3, Page 8 of 9. These show a total ratepayer cost of a little more than $2 billion through 2020. Further, if the timeframe of this analysis were extended, each additional year would add initially about $200 million to the total cost. This amount would fall slowly over time. The total Net Present Value of all ratepayer costs in 2010 under the MPRP through 2020 is about $1.1 billion, discounted at 10.0%.

The second section of the table shows the projected annual costs to ratepayers under the GridSolar Project. There are two components to these costs. The first relates to the payments made by CMP to GridSolar for grid reliability services. For this purpose, we have defined these as roughly equivalent to the avoided cost of the MPRP, or $2,000 per installed kW (of AC capacity).[7] The second is an offsetting effect related to the difference between the price of wholesale power that ratepayers would otherwise pay and the price that they will pay for power generated by the GridSolar Project and charged for on a cost-of-service basis, consistent with our Petition. The net effect of these amounts represents the costs to ratepayers under the GridSolar Project. The total cost through 2020 is a little over $1 billion with a Net Present Value in 2010 of about $656 million.

The total savings to ratepayers over this 10 year period under the GridSolar Project are almost $1 billion with an NPV of about $430 million. Further, as can be seen by comparing the incremental costs to ratepayers of the MPRP in year 2020 with the incremental cost of the GridSolar Project to ratepayers in that same year, the savings under the GridSolar Project are growing rapidly, and will continue to grow well beyond 2020 in the absence of any very significant increase in peak loads.

[7] The $2,000 per kW is computed by dividing the $1.5 billion capital cost of the MPRP by the projected increase in peak load of about 800 MW it is being built to serve. Of course, if that peak load does not grow as rapidly as CMP has forecasted, the denominator in that computation will be smaller and therefore the cost per kW larger. We have not adjusted the 800 MW peak load growth for this purpose.


Cumulative Ratepayer Costs
$000s
$2,500,000
$2,000,000
$1,500,000
$1,000,000
$500,000
$0
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
MPRP
GridSolar

Ratepayer Costs - MPRP vs. GridSolar

		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
CMP MPRP												
Annual Capital Costs	$000	15,500	94,184	481,270	543,369	377,771	38,750	0	0	0	0	0
Annual Carrying Costs	$000	11,233	54,812	140,338	221,693	256,686	249,925	239,575	229,729	220,587	211,649	202,916
Cumulative Carrying Costs	$000	11,233	66,045	206,383	428,076	684,761	934,687	1,174,262	1,403,991	1,624,578	1,836,227	2,039,143
Present Value	10.00%	1,089,207										
GridSolar												
MW Requirement - Annual	MW(AC)	15	30	70	90	110	130	140	25	20	31	32
MW Requirement - Cumulative	MW(AC)	15	45	115	205	315	445	585	610	630	661	693
Contract Payment from CMP	$/KW Installed		2,000									
Annual Rate Impact	$000	30,000	60,000	140,000	180,000	220,000	260,000	280,000	50,000	40,000	62,101	63,007
Cumulative Rate Impact	$000	30,000	90,000	230,000	410,000	630,000	890,000	1,170,000	1,220,000	1,260,000	1,322,101	1,385,108
Generation	MWh	24,205	72,616	185,574	330,805	508,311	718,089	944,005	984,347	1,016,621	1,066,727	1,117,564
Market Price	$/MWh	74.83	74.83	73.47	72.40	74.00	74.96	76.63	76.73	78.45	80.21	79.71
GridSolar Price	$/MWh	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00
Energy Savings	$000	1,085	3,255	8,068	14,026	22,366	32,288	44,020	46,002	49,254	53,557	55,557
Net Annual Costs	$000	28,915	56,745	131,932	165,974	197,634	227,712	235,980	3,998	(9,254)	8,544	7,449
Net Cumulative Costs	$000	28,915	85,660	217,592	383,566	581,200	808,911	1,044,891	1,048,889	1,039,635	1,048,179	1,055,628
Present Value	10.00%	661,860										
GridSolar Savings												
Annual Savings	$000	(17,682)	(1,933)	8,406	55,719	59,052	22,214	3,595	225,731	229,841	203,105	195,467
Cumulative Savings	$000	(17,682)	(19,615)	(11,209)	44,510	103,562	125,775	129,370	355,102	584,943	788,048	983,515

D. Job Creation

CMP has repeatedly stressed that the job creation benefits of the MPRP are substantial and must be taken into account when evaluating the MPRP on its own merits and compared to other non-transmission alternatives. We have done an analysis of the job creation potential of the MPRP compared to the GridSolar Project. The results are shown in the charts in this section.

For the MPRP case, we have used the results from the modeling done by Charles Colgan on behalf of CMP[8], except that we have pushed each year in the Colgan study out a year to account for the delays related to the start date for the MPRP. The direct and indirect jobs estimates are reproduced in the following table:

MPRP - Direct and Indirect Jobs Created

	Direct Jobs Constr.	Direct Jobs Services	Total	Indirect Jobs	Total
2010	314	187	501	190	691
2011	1,611	820	2,431	896	3,327
2012	1,583	816	2,399	888	3,287
2013	578	287	865	354	1,219
2014	0	0	0	0	0
2015	0	0	0	0	0
		Total Man-Years			**8,524**

Source: Colgan Study

Job creation under the GridSolar Project depends on a number of factors, including how rapid the build out and whether or not any of the manufacturing, fabrication, or assembly of the

[8] Economic Impacts of the Proposed Maine Power Reliability Program, Charles Colgan, February 2009.

distributed solar generation systems will be done in Maine. To estimate job creation under the GridSolar Project, we made a few assumptions:

- Build out will be as described earlier in this filing.
- Of the total capital cost of distributed solar generation, the only amount spent in Maine will be the labor component (including indirect costs such as site lease payments, permitting and overhead costs). The rest of the capital costs will be for equipment and materials that are imported from outside of Maine. This is a very conservative assumption, as some of the structural components as well as electrical components may be made in Maine.
- Once operational, GridSolar will employ people for a number of purposes, including operations, technical support, and maintenance.
- We have used the same ratio of direct jobs created to indirect jobs as used in the Colgan study.
- We have looked at two scenarios – one where there is no manufacturing or fabrication of solar generation systems in Maine and a second in which a plant roughly comparable to a Sharp facility in Memphis, TN is opened in Maine in 2011. This plant has a production capacity of approximately 50 MW a year, which is a little below the average rate of build-out over the next 10 years.

These assumptions yield the following job creation levels for the GridSolar Project over the next ten years:

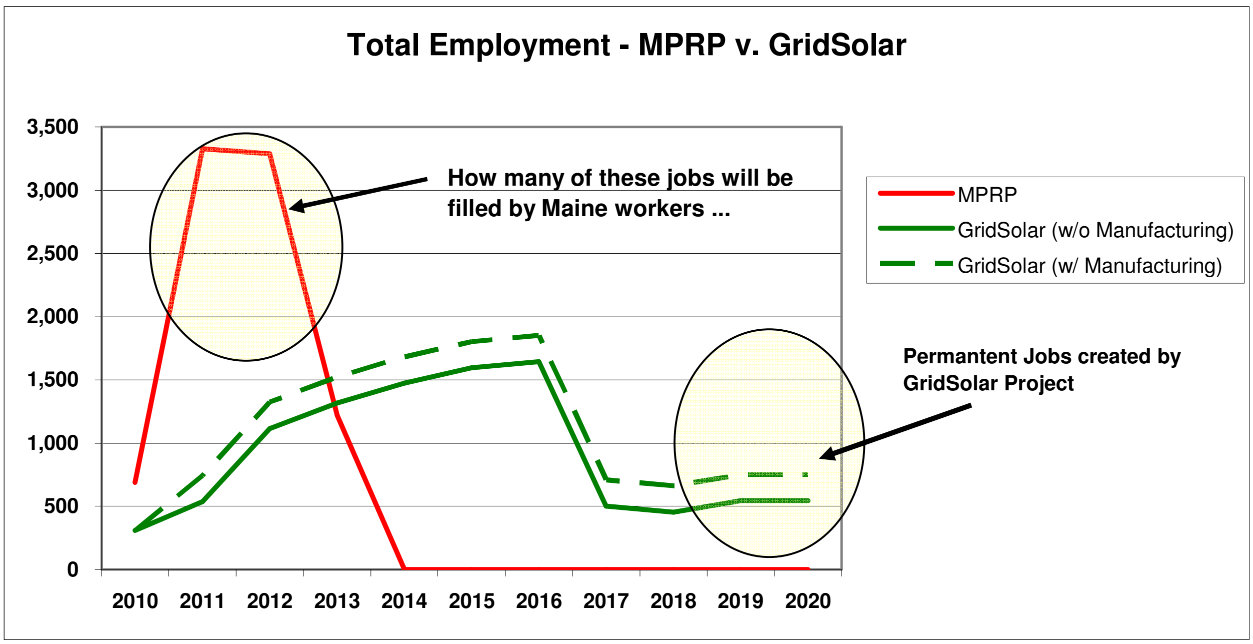
GridSolar Project - Direct and Indirect Jobs Created

	Direct Jobs	Indirect Jobs	Total	Manufacturing Scenario Direct	Indirect	Total
2010	224	86	310			310
2011	389	148	537	150	57	687
2012	807	308	1,116	150	57	1,266
2013	952	364	1,316	150	57	1,466
2014	1,067	407	1,474	150	57	1,624
2015	1,155	441	1,596	150	57	1,746
2016	1,190	454	1,644	150	57	1,794
2017	363	139	502	150	57	652
2018	329	126	455	150	57	605
2019	394	150	544	150	57	694
2020	394	150	544	150	57	694
	Total Man-Years					**11,538**

The chart below tracks the cumulative jobs created, measured in man-years. It shows that the MPRP provides more rapid job creation, but the jobs are temporary as they are related to the construction of the transmission lines. In contrast, the GridSolar Project creates fewer jobs immediately, but many more jobs over the next 10 years. Further, to the extent that the GridSolar Project can serve as a catalyst for the development of a solar industry in Maine, the number of jobs created will increase significantly beyond those shown in this chart.

This chart also raises the question of how many of the temporary jobs created over the next few years – and especially during the peak construction period – by the MPRP will be jobs filled by Maine residents. Many of these jobs are specialized jobs performed by companies that undertake this type of work for utilities across the U.S. using mobile work crews. Even where the work may be done by Maine companies, the peaked nature of the work makes it more likely that Maine companies will draw upon a national labor force for the temporary employment opportunities created by the MPRP. This issue has never been raised or discussed by CMP.

The same is not true for the GridSolar Project, which offers the very real opportunity for long-term employment in a new and high growth industry. The construction and installation jobs do not disappear after the first round of build-out is completed, but instead are retained for subsequent increases in required distributed solar generation capacities. Similarly, the operations and maintenance jobs are on-going jobs and will increase over time as more distributed solar generation sites are built out.



IV. SUMMARY

The case for the GridSolar Project as an alternative to the MPRP as a means of ensuring that CMP's bulk power transmission system has become even stronger since our filing in early 2009 and all trends indicate that it is likely to become stronger still over the next ten years. Slower economic growth and increased energy conservation will result in lower peak loads over the next ten years and beyond than those CMP has used to justify the need for the MPRP. Further, the falling costs of solar PV systems will result in still lower costs for the GridSolar Project if load growth languishes. The problem is that the MPRP cannot be phased-in or scaled back to accommodate these lower load forecasts, and as a result, ratepayers will pay a very hefty price for excess transmission capacity. Further, as technology improves the efficiencies of solar PV systems and demand drives down production costs, more and more businesses and residential customers will install such systems to meet their own electric needs. When these systems are combined with smart-grid technologies and on-site storage systems, such as plug-in hybrids, the customers will have the capability of islanding in order to avoid higher and higher fixed costs related to transmission investments. This will increase the likelihood that much of the MPRP could become stranded.

In contrast, the GridSolar Project permits a gradual build out of distributed solar generation in response to – and not in anticipation of – incremental peak load growth in the CMP service territory. The cost to ratepayers of the GridSolar Project is about half the cost of the MPRP, and could be even lower if load growth continues to languish in the sluggish Maine economy. The GridSolar Project also creates more jobs than the MPRP over the next ten years, and these jobs are more likely to be held by Maine workers. Finally, the GridSolar Project will ensure that virtually 100% of Maine load growth above and beyond 2009 peak load levels will be met by solar generation.

In summary, the GridSolar Project is a far superior strategy than the MPRP for ensuring that the CMP bulk power system meets or exceeds NERC reliability standards.

FILING BY
GRIDSOLAR, LLC

REQUEST FOR CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE GRIDSOLAR RELIABILITY PROGRAM CONSISTING OF THE DEVELOPMENT OF UP TO 800 MW OF DISTRIBUTED SOLAR GENERATION AND ASSOCIATED INTERCONNECTION AND RELIABILITY FACILITIES (“GRIDSOLAR PROJECT”)

SUPPLEMENTAL FILING

September 8, 2009

Exhibit A - GridSolar Financial Plan

CONFIDENTIAL

A revised financial model is available on the CONFIDENTIAL portion of our web site at www.competitive-energy.com/gridsolarproject. You will need a password in order to access any of the confidential information on this web site.