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Trinity Solar
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Working with the states to develop cost-effective PV policies and programs.

The Solar Alliance

November 19, 2009

2009 NOV 23 AM 9:41

RE: EXPRESS TERMS - SAPA No. 03-E-0188SP22
Renewable Portfolio Standard – Case 03-E-0188

Honorable Jaclyn A. Brilling
Secretary to the Commission
New York State Public Service Commission
Empire State Plaza, Agency Building 3
Albany, NY 12223-1350

Dear Secretary Brilling:

Please find enclosed for filing an original and five (5) copies of the Solar Alliance's Comments on RPS Mid-Course Review in the above-referenced matter.

Please do not hesitate to contact me at the number below should you have any questions.

Sincerely,

Fred Zalcman
Solar Alliance, New York Team Leader

Fred Zalcman
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NEW YORK STATE
PUBLIC SERVICE COMMISSION

Proceeding on Motion of the Commission) **Case 03-E-1088**
Regarding a Renewable Portfolio Standard)

SOLAR ALLIANCE COMMENTS ON
RPS MID-COURSE REVIEW
November 2009

INTRODUCTION AND SUMMARY

The Solar Alliance, a coalition of over 30 of the world's leading solar photovoltaic (PV) manufacturers, developers and financiers focused on advancing state-based solar energy markets, respectfully submits the following comments[1] directed to the New York Public Service Commission's ongoing "mid-course" investigation into the future direction of the Renewable Portfolio Standard ("RPS"). This set of comments build on our previous submissions to the Commission wherein we have detailed the many and significant customer/host, ratepayer and societal benefits accompanying greater funding and deployment of solar PV in New York State; and made programmatic recommendations for most expeditiously and cost-effectively bringing these resources on-line.

In these comments, we respond directly to the findings and recommendations set forth in the October 26, 2009 Mid-Course Report prepared by the Staff of the Department of Public Service (hereinafter referred to as "Report"). Specifically:

1. We take serious exception to the cost-benefit analysis conducted by the DPS Staff related to future RPS program investment in PV. In short, we believe the analysis is based on a very static, backward looking review of the installed cost of PV and therefore grossly overstates the cost of future delivery of PV incentives

[1] These comments represent the collective views of the Solar Alliance, and not necessarily those of an individual member company.

to stimulate private investment. On the benefit side of the ledger, while the Report acknowledges the multiple, hard-to-quantify benefit streams of PV, these benefits are inadequately incorporated into the analysis. The net result is a skewed picture of PV costs and benefits relative to other RPS-eligible technologies and uses of ratepayer funds, which if not corrected, could constrain sound decision making.

2. The Solar Alliance recommends several short-term refinements to the current PV incentive program aimed at residential and small commercial market segments that will enhance the cost-effectiveness of the program and lead to a more sustained and orderly development of the local PV industry.

3. The Solar Alliance recommends an extension of current program opportunities to encompass the large commercial, institutional and industrial market segments in order to exploit economies of scale in PV development and provide a more equitable opportunity for all customer classes to deploy clean, stable-priced, on-site renewable energy generation.

4. The current dichotomy between Main Tier and Customer Sited Tier technologies does not adequately serve the full range of PV deployment strategies. In particular, large-scale distributed solar that can provide localized benefits in high-cost, resource constrained segments of the grid fall between the cracks under the current RPS program structure and this gap should be addressed.

5. Solar PV can be a major contributor to addressing perceived regional inequities regarding funding and deployment of RPS resources.

6. Utilities should be encouraged to play a more significant role in the deployment of PV resources.

Our suggestions regarding PV program delivery are encapsulated in the following chart, and discussed in further detail in Section II of these comments:

Market segment	Mechanism	Notes
Residential & small commercial <10 kw	Expected performance based buydown (capacity rebate)	Similar to current NYSERDA program with simplified application procedures; 15% adder for in-city projects
Commercial/institutional <80 kw	Fixed performance based incentive (PBI) (10-15 yr.) with declining block structure	15% adder for in-city projects
80 kw – 2,000 kw	Either fixed PBI or PBI with price set by market mechanism (auction); 10-15 year term	Commission and NYSERDA to determine lower threshold limit for market based incentive; 15% adder for in-city projects under PBI
Main Tier RPS for grid connected solar	50 MW solicitation for in-city PV; bidders submit fixed price using contract for differences approach (10-15 year contract)	No explicit lower or upper project size specification
Utility Tier	Ratebase (utility owned PV) or expensing (contractual or tariffed costs for third party projects)	Subject to level playing field considerations

I. THE DPS STAFF REPORT OF PV COSTS AND BENEFITS IS DEEPLY FLAWED AND, UNLESS CORRECTED, WILL PROVIDE AN INFIRM ANALYTICAL FOUNDATION FOR COMMISSION DECISION ON PV PROGRAM DESIGN, GOALS AND FUNDING.

The DPS Staff Report has routinely overestimated the cost of PV under the Customer-Sited Tier while routinely discounting or ignoring important benefits provided by this portfolio element. In addition, Staff's analysis is fundamentally flawed because it does not consider a more well designed and robust CST program that is intended to reduce incentives for distributed PV ("CST-PV") to zero over time in a transparent fashion. Comprehensively designed solar programs like those found in California, Colorado and Maryland each have as a critical program element the eventual reduction to zero of the incentives provided. These programs are designed to propel the solar industry to cost effectiveness by the time of program conclusion and are inherently cost effective when incentives are no longer needed.

Understandably, the Report's combination of two valuation errors when together with a flawed design, leads Staff to question whether the public interest is served by a doubling of PV expenditures. The Commission should direct Staff to reconsider both the costs and benefits of the CST-PV program and do so in light of a better overall solar program design – one that has the ability to eventually reduce incentives to zero in a transparent and planned fashion. The benefit of that ultimate solar program design – a clean affordable energy source that as the Report notes is available in all areas of New York – will far outweigh the interim costs of this aspect of the CST. That ultimate goal can only be reached, however, with an expansion of the current allocation to PV under the CST and/or other RPS program elements.

A. The Costs of Delivering Photovoltaic Energy in New York Have Been Overstated.

Staff quotes several different and apparently historic energy costs for distributed solar PV, all of which appear to be significantly high and none of which build on both the anticipated cost declines projected for PV in the US and the lower costs that can be achieved from a well designed, long term and large CTS PV program. Staff at Table 3 quotes an PV energy price of $67/MWh.[2] The Report states "Solar PV installations produce electricity at a cost of between 30 cents and 44 cents/KWh".[3] While both of these costs may be accurate based on historic installations in New York and production therefrom, it is an erroneous basis on which to predicate program costs going forward. As discussed later, costs of installed solar have steadily declined over time; significant cost reductions have been posted from the beginning of the year. Moreover, Staff has, to greater or lesser extent, overstated the costs of CST-PV program based on the following flaws:

- Lack of a long-term program design focused on driving CST-PV to cost effectiveness
- CST-PV program design (and recommendations) based on historic installation costs without reliance on the well publicized cost reduction potential in PV installations

[2] See Report at Table 3.
[3] See Report at p. 55.

- An 80 kW cap on the size of an installation which increases the per unit cost and does not take advantage of economies of scale in PV installations
- A small program in terms of annual MW of CST-PV to be installed which deters solar businesses from making investments in the state that will reduce fixed costs
- Rebate design with a relatively fixed level of incentives which neither advantages lower cost installations nor is transparently responsive to potential cost reductions in the PV industry
- Rebate design which does not encourage greater energy production from CST-PV which in turn can lead to higher per MWh energy rates from this market segment
- Front loaded fixed rebates which reflect higher initial program costs and do not take advantage of the long life of a PV asset

1. <u>Better designed solar programs provide long-term declining incentives which drive the industry towards grid parity.</u>

In California under the California Solar Initiative (CSI)[4], customers who install on-site solar energy systems not larger than 1 MW in capacity are eligible to receive a performance based incentive payment (PBI) for the solar energy produced from their on-site systems.[5] The PBI, paid in cents/kWh, is designed to decline with increasing volume of solar installations. The California Public Utilities Commission (CPUC) identified a series of ten "steps" when the CSI program was released starting with a PBI payment for residential and commercial customers of 39 cents/kWh for step 1 and declining to a 3 cents/kWh incentive by the time the CSI program reaches step 10.[6] Currently, the CSI Programs have seen aggressive installations and

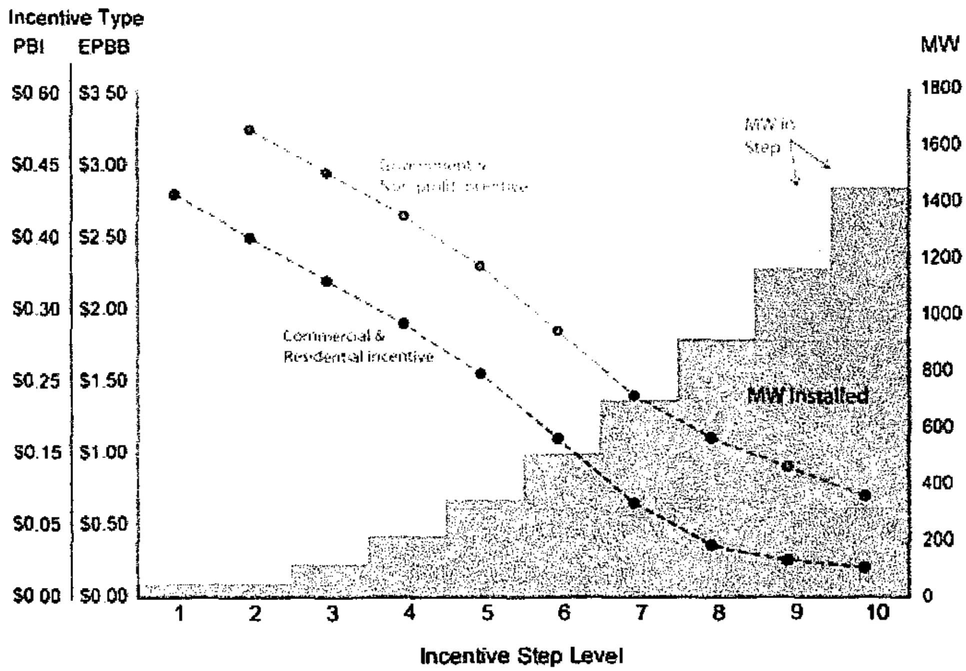
[4] The CSI Program has a goal of incentivizing the installation of 1750 MW of distributed PV on existing homes and businesses over the 10-year life of the program. The program operates within the service territories of California's three largest investor-owned utilities: Pacific Gas and Electric Company, Southern California Edison, and San Diego Gas & Electric Company. It is part of the *Go Solar, California!* campaign that seeks to incentivize the installation of 3,000 MW of distributed PV in California over the 10 year life of the campaign. Other portions of the campaign focus on installation of solar on new homes and solar programs administered by the state's publicly-owned utilities.

[5] In 2008-2009, PV systems smaller than 50kW are eligible to receive an upfront incentive based on expected performance called the Expected Performance-Based Buydown ("EPBB"). Starting in 2010, the EPBB will only be available to systems below 30kW in size.

[6] See Decision No. 06-12-023, Appendix B, Table 3, pg. 2 (showing modifications to D.06-08-028 based on the passage of Senate Bill No. 1).

concomitant PBI price step declines that have placed all of the utility programs in PBI step 5 or 6 (22 and 15 cents PBI payments respectively).[7]

It is noteworthy that the original design of the CSI which anticipated a 10 year program to end in 2016 with roughly a single step reduction each year has accelerated to step 5 or 6 by the third year of the program. This means the State has a much higher volume of solar installations with a much more aggressive reduction in ratepayer incentives than originally anticipated. This higher volume and lower program cost is typical of a well-designed long-term program.
The table below shows an overview of the CSI step level changes as the MW goals of each step are met.[8]



PBI: Performance Based Incentive, paid over 5 years, in $/kWh
EPBB: Expected Performance Based Buydown, paid upfront, in $/W

Figure 1. Overview of the CSI Step Level Changes

In Colorado, Xcel Energy, the predominant electric utility in the state, has a utility administered customer-sited solar program, called Solar*Rewards, authorized by the

[7] See California Solar Initiative Quarterly Staff Progress Report - October 2009, prepared by California Public Utilities Commission Energy Division Staff, available at: http://www.cpuc.ca.gov/PUC/energy/Solar/091021_staffprogressreport.htm.
[8] The latest data on the CSI program incentive levels and installed MWs is available at http://www.csi-trigger.com/.

Colorado Public Utilities Commission with statutory authority from Amendment 37 - a statewide citizens' referendum. Xcel has designed the program to pay a fixed $2.00/watt incentive upon installation of systems up to 500 kW capped at $200,000 plus a series of declining cents/kWh incentives for the purchase of the renewable energy credits produced by the solar energy system.[9] The decline in the price of the solar RECs is based on an increasingly larger number of solar MW installed over a series of 11 or 12 declining steps. Xcel's Solar*Rewards program is paired with routine utility RFP's for larger solar PV projects above 500 kW. The combined programs are anticipated to install solar sufficient to meet 0.8 percent of the state's electricity needs[10]. In the final step of the Solar*Rewards program for small systems, the incentive is reduced to 0.01 cent/kWh. For larger systems above 10kW, the final incentive is $5/MWh.

As in California, this program evinces a design destined to drive solar incentives to zero in a transparent, predictable fashion with inherent long-term cost savings. Currently, Xcel is paying an incentive of 11 cents/kWh for small systems and $125/MWh for systems up to 500kW. Since the Xcel incentives like the PBI in California are incentives paid on production behind the customer's utility revenue meter the value to the customer is both the retail utility rate plus the incentive amount.

In Maryland, the General Assembly enacted a solar REC-based program in 2007 that requires electricity suppliers in the State to purchase RECs from solar installations through 2022. The Maryland program incorporates an annual cap or "alternative compliance payment" (ACP) on the price of a solar REC. The ACP declines each year (or every 2 years). The Maryland ACP starts at $450/MWh and declines to $100/MWh by program conclusion (with no special requirement to purchase solar RECs after 2022). Because solar project developers must both compete among other developers to sell solar RECs to utilities and must offer a price less than the declining steps of the ACP, the actual cost of solar incentives will be less than the ACP value.

As in Colorado and California, solar customers in Maryland receive the incentive payment in addition to offset retail rates. In Maryland there is no system size limit

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[9] For certain residential customers, the incentive on a per kWh incentive basis may be taken as an "upfront" one-time payment based on the per watt DC capacity of the installation based on the system size in watts DC. For systems owned by third-parties developers, the "upfront" one-time payment option is not available. RECs produced by third-party owned systems are paid on a cents/kWh basis.
[10] The Database of State Incentives for Renewable Energy (DSIRE), (2009) Colorado overview (http://www.dsireusa.org/incentives/index.cfm?re=1&ee=1&spv=0&st=0&srp=1&state=CO)

other than the requirement that qualified solar installations are connected to the distribution grid serving the state. Under the State's interconnection rules all generators up to 2MW in size will qualify.

Each of the above state programs has the following commonalities (and benefits):

- Long-term program design – allows solar companies to invest in the solar market knowing the program will be there to support their efforts over a longer term than one or two years;
- Declining incentives which decline in a predictable and transparent fashion based on MWs installed – declining incentives drive companies to efficiency and transparency in declines allows companies to understand and plan for programmatic changes;
- A sizeable amount of total solar MW installed by program conclusion – gives companies some assurance that their investments in entering a state will pay off if they compete for business;
- Long-term payments based on energy production (CA PBI – 5 years; CO -- 20 year payment; MD - 15 year REC contract term) – long-term payments facilitate financing of systems and basing those payments on the energy produced ensures ratepayers will only "get what they pay for".

These program design elements are critical to ensuring any solar program can reach cost effectiveness because each of these program design elements provides the programmatic stability necessary to allow solar companies to invest their resources and compete. It is this investment and competition that will ultimately determine the success of state solar incentive programs. Unfortunately, these program design elements are currently missing from the CST-PV program structure in New York. Without them, solar installation costs and need for incentives will be higher than necessary to incentivize the transformation of New York's solar industry.

2. <u>CST-PV Program costs are predicated on historic installation costs not projections of the level of incentives necessary to promote investment in CST-PV going forward</u>.

Staff appears to have used a fixed decline in its projections for rebates without any correlation to projected cost declines in the solar industry. In Table 6 of the Report, the net rebate cost appears to begin at $3 per/watt then decline by a straight 10 cents/watt each year to reach \$2.50 in 2015. Staff's approach is assumed to be that the current rebate level will remain unchanged in 2010.[11]

While this approach and assumption may reflect the recent historic prices of installations in New York, it does not comport with the projections in the solar industry of cost declines nor does it follow the more aggressive declines in incentives seen in states like California or Colorado. In a recent article in Greentech Media, the paper noted that long-term prices for silicon, the fundamental raw material for mono and polycrystalline solar panels, has "dived about 50 percent"[12]. The article went on to note that First Solar, a manufacturer of non-silicon based thin film solar panels, now has a cost of production for their modules at \$0.87/watt. "[First Solar] reportedly is selling its panels at below \$2 per watt while silicon panel makers are selling theirs at roughly \$2.25 to \$2.50 per watt." Assuming modules are about one-half of the total cost of a solar PV installation, in theory systems could be installed in the relatively near term in the \$4 to \$5/watt range. A rebate level at \$3 dropping to \$2.80 in 2012 as Staff assumes is more than likely on the extreme high end of the level of incentive needed in a market of \$4 to \$5 per watt installations. In fact, if the solar industry can achieve the installation target of \$5 per watt by 2012, using a simple mathematical application of the federal ITC reveals a net cost of \$3.50 per watt. Were New York to pay \$2.80 in rebates in 2012, it would be covering 80 percent of the net of ITC costs and would be providing customers with a solar power source well below retail electric rates.

Staff should update its analysis based on the recent decline in incentives in New York and also reduce its assumed rebate levels for the outer years in the CST-PV program to reflect reductions in future incentive levels based on anticipated cost declines in the industry. Using inflated projections of program costs, as Staff does, leads to a less cost effective program than one that assumes more realistic declines in rebate levels as solar costs decline.

3. <u>The 80kW cap on participating systems in the CST-PV program is too low and raises the program cost.</u>

A recent report by Lawrence Berkeley National Laboratory (LBNL) that reviewed the installed cost of solar PV in the US over the last ten years notes that PV installations

[11] Subsequent to the issuance of the Report, NYSERDA reduced the rebate level by 50 cents per watt for residential and commercial customers and by \$1.00 per watt for non-profit customers.
[12] "First Solar Fears Competition From Silicon Panel Makers", July 30, 2009, Greentech Media.

in the 500 to 750kW range are about 30 percent less than the smallest systems[13]. This finding is intuitive as the larger PV systems enjoy economies of scale in installation not found in smaller systems. The Report embraces this understanding noting that "[w]ithin certain of these technologies (e.g., solar PV), there are economies of scale, such that large installations produce energy at a lower cost/MWh" but then fails to propose a PV program that can take advantage of these economies of scale (Report p. 49).

By limiting participation in the program to systems 80kW and below, the New York program has eliminated the most cost effective PV systems from participation in the CST-PV program, thereby, inflating the costs of installation relative to programs that allow larger systems to participate. The low system size limit leads to a less cost effective program than one that allows larger systems to participate. The low system size limit is also at odds with New York's net metering program which allows systems of up to 2 MW to net meter. Harmonizing incentive levels with net metering would allow these two programs to work together to support the growth of New York's solar market. To achieve these ends, Staff should be directed to analyze a program that would allow larger and lower cost systems in its benefit/cost analysis. The Solar Alliance would recommend Staff consider the economies of 2 MW installations and model the reduced costs of these systems relative to the current 80kw limit. Those reduced costs should be incorporated into a new cost benefit analysis.

4. New York has a small size of the CST-PV program relative to other states leads to higher costs.

In order for the PV industry to make a serious investment in a state, there must be some assurance of a large and stable market. Investments in distribution channels, local sales people, contractors and supervisors, local offices, and legal costs to understand the state's rules and regulations are all fixed costs for solar PV companies which must be recovered incrementally over the total number of installations in the jurisdiction. When that total overall market potential is small compared to other states, a state's program will attract fewer solar companies because other markets are seen as offering a greater reward for the same or similar investments. Fewer companies leads to less competition in the state's solar market which ultimately leads to higher costs. Furthermore, those companies that do enter

[13] Tracking the Sun II, The Installed Cost of Photovoltaics in the U.S. from 1998-2008, (October 2009), R. Wiser, Lawrence Berkeley National Laboratory (hereinafter cited as Tracking the Sun II).

the state market must recover their fixed costs over a smaller number of installations leading to higher costs per installation.

From Table 6 in the staff report, New York projects a CST-PV program of just over 52 MW through 2015. This contrasts with solar program targets of approximately 1800 MW in the California CSI, 1500 MW in New Jersey and Maryland, and 270 MW in Colorado. Naturally, the larger programs in those other states will attract a larger and more diverse set of solar competitors than the New York program, which is less than one-tenth the size of these state solar programs. Investments made to enter the solar market in the larger program states will be recovered over a long period and large number of installations. Thus, each will have a lower cost than those in New York.

When higher installation costs are combined with the inordinately low solar system capacity cap in New York, the State is ensuring that it will see much higher per watt installation costs than other states. In essence what the New York CST-PV program does is ask the PV community to attempt to be cost effective under dual size constraints. It would be equivalent to a determination that nuclear power was extremely costly and not cost effective because the State sought only a 52 MW nuclear facility with a requirement that no individual unit at the plant should have a capacity of more than 80 kW. These restrictions sound absurd when put in the nuclear context but have a similar impact on solar PV costs.

5. A PV program based on fixed rebates does not obtain lower costs that may become available to solar installation companies.

In the state solar programs cited above, competition encourages solar project installers to lower price as their costs decline and these competitive market pressures are reinforced by automatic reductions in incentives based on the volume of projects installed. This framework makes sense given the fact that these programs are predicated on encouraging the growth of a competitive solar market by stimulating the demand for solar via targeted ratepayer incentives. Automatic declines in incentive levels based on the volume of installed systems reinforces the idea that as the industry progresses down the learning curve, installed costs will decline.[14] Competition for customers encourages solar companies to lower prices in

[14] The Report recognizes the impact increasing sales volume has on overall installed costs for PV. See pg. 107.

order to obtain the greater allocation of MW available in the next step or tier of the program.

Fixing a rebate level without automatic, transparent reductions in incentive levels based on volume leads to a higher cost solar program than are necessary. Transparency in rebate reductions is critical because without foresight into anticipated incentive reductions companies face uncertainty surrounding what rebate level to quote to customers when discussing the economics of the customer's potential investment in a solar energy system. This uncertainty undermines the ability of solar companies to grow their business. Moreover, unexpected declines in incentive levels can lead to customer confusion which further undermines the growth of the solar industry.

New York, in setting its rebate level, must identify a level sufficiently high that it is economical for customers to invest in solar projects. that goal must be balanced against the desire to ensure the rebate level is not too high that it results in program costs greater than they need to be. It appears Staff in its projections has achieved the former, but at the expense of a potentially very costly program.

The Solar Alliance has no doubts that the rebate levels are sufficient to meet the modest installation targets for the CST-PV program but is concerned that the level of rebate selected by Staff has not been sufficiently refined to ensure the costs are as low as possible. Were program administrators to design a program that reduces rebate levels transparently as installation targets are achieved as the other state solar programs do, it would lead to a less costly program and greater cost effectiveness under all of the cost effectiveness tests Staff employs.

6. <u>Front loaded rebates reflect a higher initial cost and do not take advantage of the long life of the PV asset</u>.

Staff notes that there may be benefits to a structure of the RPS that avoids the front loaded payments currently made (Staff report p.87). The Solar Alliance would agree and submits that payments made under the CST-PV program based on solar energy production will lead to a less costly program and a higher overall cost effectiveness. Because the costs of a PV installation are nearly fixed the day it is installed, making incentive payments over time works well for this energy resource. Moreover, PV systems today typically come with warranties of 20 to 25 years and can be expected to produce power for 35 years or longer.

Provided the incentive payment stream is secured at the time of installation, it is relatively easy to finance the cost of a PV system. From the program perspective, the funds available currently in the form of rebates can be leveraged for a much higher number of installations which can, in part, address the need for a larger program without a concomitant need for a significantly larger budget. Because the revenues available to pay upfront rebates would be an order of magnitude higher that the amounts paid in year one of a performance based incentive, the set budget for rebates can support a much higher volume of MW installed in the early years. The total obligation to pay incentives will be enlarged but spread out over time. A larger performance based payment would oblige the State to pay for incentives after the program is concluded in 2015 with a concomitant increase in the total aggregate cost of the program to cover the increased volume in MW. A 10-15 year PBI style payment can be easily accommodated by the solar industry and the Solar Alliance would recommend Staff consider as part of a revised cost-benefit analysis an alternative program with such an elongated incentive.

B. The Value of PV Energy Has Not Been Fully or Effectively Captured in the Staff Cost-Benefit Analysis.

With respect to the CST-PV program, the Report repeatedly discounts or ignores certain beneficial aspects of distributed PV. While the Report undertakes a partial benefits analysis for a hypothetical PV installation in New York City and derives an "adder" for PV of 115%, this analysis both fails to incorporate a host of other benefits distributed PV provides and does not seem to be systematically incorporated into the Report's CST-PV cost benefit analysis. Combined with the inflation of costs of CST-PV program discussed above, the suppression of benefits leads Staff to the erroneous conclusion that the CST-PV program is not cost effective.

Staff should consider incorporating the following benefits that distributed PV provides into any cost-effectiveness analysis of the CST-PV program as inclusion of these benefits enhance the accuracy of any cost effectiveness analysis performed on the CST-PV program:

- Additional price suppression beyond the KEMA identified benefits of $2 billion for Main Tier resources and related to solar PV's concentrated reduction in the need for costly peak generation.
- Removal of any price suppression deduction for lost sales to existing generators

- Additional solar distributed generation benefits
- Reliability – blackout prevention benefit
- Jobs and economic development

1. PV deployment supports additional price suppression beyond the KEMA identified benefits of $2 billion for Main Tier resources.

The Report rejects KEMA's conclusion that the Main Tier of the RPS will lead to price suppression in the NY ISO generation markets of $2.8 billion over the life of the program with $323 million in benefits in 2010.[15] In addressing this analysis, Staff says simply "KEMA's estimated value of price suppression ...for the first three main tier procurements appears to be high."[16] In fact, the opposite is true; the KEMA report understates the value of price suppression with respect to PV.

The KEMA analysis is focused on the reduction in wholesale prices related to the injection in the ISO generation stack of a non-fuel resource (which will have a very low marginal cost presumably below any other generation resource). KEMA uses the Main Tier resources from the RPS to undertake this analysis, which means the new generation resource is predominantly wind. While solar PV will have the same general effect on the generation stack as wind resources, leading to the price suppression impact of PV to be at least as great as a wind resource, the energy output from PV is concentrated during the times when ISO generation prices are likely higher than average.

In fact, PV tends to have direct correlation with the highest cost generation hours. A recent study jointly commissioned by the Solar Alliance and the New York Solar Industries Association analyzed the real-time locational based marginal price in various New York markets for 2007 based on a weighting of PV output to the coincident market price. The study authors find that "because of the strong coincidence that exists between peak demand and solar resource availability both downstate and upstate, the generation energy and capacity value of PV alone" amount to 75% of the full *retail* rate. [17] A summary of the study is provided at Attachment A.

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[15] See KEMA at 5-15 and 5-16.

[16] Report at 80 and 81.

[17] Perez, Richard and Hoff, Thomas, *Energy and Capacity Valuation of Photovoltaic Generation in New York* (2008).

Because of this direct correlation with the highest cost generation hours, PV also has a great price suppression impact than the average resource. Staff notes this aspect of PV generation in their Report but fails to take this into account in analyzing price suppression.[18]

In a paper studying the effects of PV penetration on the hourly clearing price in ISO-NE, researchers identified a 2 to 6 percent reduction in overall prices from a large deployment of distributed PV.[19] When this savings was applied as a net present value benefit to the initial cost of PV, it was determined to be worth $1.50 to $3.30 per watt – possibly half the anticipated cost of a PV installation in 2012.[20]

A proper price suppression analysis for the injection of PV would add a zero marginal fuel resource into the ISO generation stack, but the resource addition would follow the generation curve of a PV system. Therefore, output would have a concentrated impact on the high cost generation periods in the ISO. The Solar Alliance has not undertaken this analysis but believes the price suppression effect from PV will be significantly greater than the baseload renewable resources KEMA used. This beneficial aspect of PV generation should be properly assigned in the Report's cost effectiveness analysis for the CST-PV program.

2. <u>The Report erroneously treats price suppression deduction for lost sales to existing generators as a cost of the PV program</u>.

As part of its rejection of the KEMA price suppression benefit, the Report identifies a concern about lost sales to existing generators and discounts the KEMA valuation based on this concern. The Report notes "The KEMA combined B/C ratio disregards the negative effect of the RPS program on existing generators. Existing generators experience losses when added renewable resources lead to lowered wholesale electricity prices." (Report at p. 80)

The Report's concern is misplaced for several reasons: first, in a competitive wholesale generation environment as exists in New York, the marketplace will

[18] Report at 55.
[19] K. Martin, *Thought Experiment—How PV Reduces Wholesale Power Prices in New England*, Photon International (2004) December 2004 (http://www.photon-magazine.com/news/news_04-12_am_feat_PVImpact_on_Electricity_Price.htm)
[20] <u>Ibid</u>.

address reduction in load for any reason and lost sales and profitability should not be a concern of regulators. Once an element of the production and delivery of electricity has been turned over to the market, the "invisible hand of the market" becomes the regulator. Moreover with fluidity among neighboring ISO's, any lost generator sales in one region will simply be redirected into a neighboring ISO with presumably little loss in profitability. Second, if there is anticipated load growth in New York or the neighboring ISO's and that load growth surpasses the new generation from RPS generators, there are no lost sales. Renewable generators simply displace non-renewable generators that would have been built to meet the new load. In some cases, the non-renewable generators will still be needed and only have their construction start dates deferred.

Third, since in a competitive wholesale generation market rates of return on generator investments are opaque, the lost sales, while lowering returns to an individual generator may still allow that generator to be a profitable investment. In other words if a generator is earning a return of 30 percent with sales of X, it might still earn a profitable return of 20 percent if sales drop to 0.9X. So even though sales have decreased and revenues lost. It should not be a concern to Staff related to the renewable program design unless generators were forced out of the pool of competition. There is no indication or analysis that suggests this will happen.

Fourth, the lost sales could allow generators that are not profitable but are maintained in the generator pool solely for reliability purposes to be retired. In this case, not only would the lost sales not be a detriment, it would properly be considered a benefit.

Unless a more rigorous analysis of the true impact of lost sales on the ISO generation market is undertaken, the Report should not discount the KEMA price suppression valuation for lost sales to other generators. Accordingly, lost sales should be excluded as a consideration of the RPS program's cost effectiveness calculations at the present time.

3. Staff should endeavor to provide a range of solar distributed generation benefits for purposes of the instant proceeding, while commissioning a more rigorous analysis for ongoing decisionmaking with respect to RPS program funding.

VoteSolar, a non-profit solar advocacy group based in California, undertook a study to determine the categories of benefits that distributed PV is able to provide.[21] The Smeloff Study found that distributed PV provided benefits in the following categories:

- Peaking Generation Avoided Cost
- Capacity Value of Solar Power Generation
- Value of Avoided Operations & Maintenance (O&M) Costs
- Benefits of Avoided Natural Gas Use
- Avoided Fuel and Variable O&M for Peak Power
- Non-Peak Periods of Power Generation
- Environmental Benefits
- Avoided Environmental Costs of Solar Generated Electricity
- Avoided Line Losses
- Deferral of Transmission and Distribution (T&D) Upgrades

Unfortunately, the Report undertakes a very limited analysis of the benefits beyond price suppression PV is able to provide by looking at only three of the above categories.

Apparently based on hourly ISO LMP data, the Report determines that a PV system located in New York City would have a 34% premium compared to the value of baseload generation because of that location. Because of the peaking value of solar generation, the Report adds another 34% adder and then adds an adder for distribution benefits for a total added value of 115% above baseload generation.[22] Unfortunately, the Report seems to wholly overlook the following benefits identified in the Smeloff Study and have also been recognized in other studies and

[21] QUANTIFYING THE BENEFITS OF SOLAR POWER FOR CALIFORNIA, (2005) E. Smeloff (on behalf of the Vote Solar Initiative), available at: http://votesolar.org/wp-content/uploads/2009/11/tools_QuantifyingSolarsBenefits.pdf ("Smeloff Study").

[22] See Report at pp. 55-56.

methodologies: Capacity value; avoided O&M costs; benefits of avoided natural gas costs (the marginal resource in NYISO); deferral of T&D upgrades.

Because it is unclear how the Report arrived at the $39/MWh benefit for avoided distributed costs, the Solar Alliance cannot determine if this benefit attribute completely covers all of the distribution benefits distributed PV is capable of providing. CST-PV program benefits go beyond just avoiding distribution losses, since these systems are by definition at the customer location, they offset losses and improve O&M expenditures from the generation level down to the service transformers serving individual customers. T&D deferral benefits are quantified in the Smeloff Study and range from $0.045/kWh to $0.101/kWh.[23] A recent study by RW Beck prepared for Arizona Public Service after extensive stakeholder input found T&D deferrals were possible with sufficient penetration of solar PV systems with a value of up to $0.82 cents/kWh.[24] In approving Southern California Edison's 500 MW Solar PV Program, the California PUC recognized that transmission costs are significant in accessing larger renewable resources and that distributed PV avoided these costs.[25] By way of example, the CPUC valued these transmission costs at $1/watt.[26] A recent NREL study found T&D deferral benefits of up to $0.10/kWh.[27] Clearly there is a broad consensus that T&D deferral benefits are available and significant from distributed PV and, therefore, should be measured clearly and accurately.

The Report's failure to include benefits stemming from deferral of generation capacity, avoided O&M costs, and avoided natural gas costs is equally problematic. For example, a RW Beck Study conducted on behalf of Arizona Public Service found significant fixed O&M savings and deferral of generation capacity in the range of 0.81-3.22 cents/kWh and significant savings from deferral of generation capacity of up to 1.85 cents/kWh.[28] The NREL Report found capacity costs savings in the range of 1.1 – 10.8 cents/kWh.[29] Lastly, the natural gas market experiences similar benefits to those seen in the wholesale electric market from the introduction of PV

[23] See Smeloff Study at pp. 20-21.
[24] see Distributed Renewable Energy Operating Impacts and Valuation Study, prepared by RW Beck, January 2009 at p.xxii and Secs. 3 and 4 ("RW Beck Study") available at: http://solarfuturearizona.com/.
[25] See Decision No. 09-06-049 at p. 32; see also pp. 10, 11, 26, and 36 wherein the Commission recognizes the T&D value of distributed PV resources).
[26] See Id.
[27] See Photovoltaics Value Analysis, Contreras, J.L. et al., February 2008 (NREL/SR-581-42303) ("NREL Report") available at: http://www1.eere.energy.gov/solar/pdfs/42303.pdf.
[28] See RW Beck Study at Sec. 5.
[29] NREL Report at pp. 7, 9-10.

resources as PV resources lower the demand for natural gas thereby lowering the price for natural gas. This benefit extends to all consumers of natural gas and is quantifiable. In fact, a recent study by LBNL quantified this benefit at $5/MWh.[30] Given the magnitude of the savings discussed in these reports and the ability to quantify these benefits demonstrated by these reports, these benefits must be included in any cost effectiveness assessment of distributed PV.

The distributed nature of PV also provides local voltage support; can reduce the need for spinning reserves; can be built within a relatively short period of time; and can be added incrementally. As developments with dynamic inverters progresses, system operators will, in the future, be able to have localized voltage and VAR control throughout the distribution system making the entire power delivery structure more efficient. While these benefits can be more difficult to quantify than the ones discussed previously, they still represent significant value streams. Simply because a benefit is difficult to quantify does not justify the assignment of zero value to that identified benefit. If it is a recognized benefit, it is clear that a zero valuation is incorrect. For example, the provision of ancillary services was valued in the NREL Report at up to 1.5 cents/kWh alone.[31] To apply a zero value to all of these benefits would clearly result in a benefit/cost ratio that is erroneous.

Inclusion of the above benefits will increase the accuracy of the cost effectiveness analysis performed in the Report for the CST-PV program. Moreover, while the precise savings identified in the Smeloff Study, the RW Beck Study and other studies vary, what is worth noting here is that the savings discussed in those studies and decisions that the Report currently ignores are quantifiable and significant and, therefore, worthy of inclusion in any cost effectiveness analysis presented to the New York Commission.

To ensure the benefits of PV are accurately assessed, the Solar Alliance would recommend that Staff be directed to include all of the benefits identified above and develop a valuation methodology based on the Smeloff Report or the others discussed above for purposes of the instant proceeding. Once that analysis is performed, the benefits quantified by the methodology can be used in determining a new benefit/cost ratio for the CST-PV program element. Additionally, the Solar Alliance would also recommend that DPS Staff, in consultation with NYSERDA,

[30] See Easing the Natural Gas Crisis: Reducing Natural Gas Prices through Increased Deployment of Renewable Energy and Energy Efficiency, Wiser, Ryan et al., (LBNL-56756) available at: http://eetd.lbl.gov/EA/EMP/reports/56756.pdf.

[31] See NREL Report at pp. 13.

develop a more comprehensive, rigorous, and New York State specific analysis of PV benefits for purposes of ongoing funding and program decisions.

4. The Report does not recognize the value of PV in preventing low-risk, high consequence events such as system-wide blackouts.

Shortly after the blackouts in the Northeast in 2003, a group of researchers undertook an analysis of the causes of the blackout and determined "there is much evidence that, had a local dispersed PV generation base amounting to at most a few hundred MW been on line, power transfers would have been reduced, point of use generation and voltage support would have been enhanced and uncontrolled events would not have evolved into the massive blackout."[32]

As the authors note, certainly there are more direct ways to address blackout prevention than by a program of dedicated deployment of PV, but nonetheless, any program that is encouraging PV installations should incorporate this benefit. The Report has not done so in its cost effectiveness analysis.

Even a rudimentary calculation of the benefits related to blackout prevention show this to be a substantial benefit. The total costs of the blackout to the region affected have been estimated at between $4.5 and $10 billion.[33] Assuming the amount PV deployment needed to have forestalled the outage was at 600MW[34], then even at the low end of the cost range of the blackout, the PV is worth $7.50/watt -- more than double the current incentive payment. Moreover, this value is more than the projected total cost to deploy PV in New York (see aforementioned PV installation cost estimates in 2012).

Of course there is no way to determine when the next major blackout will occur or, subsequent to the deployment of PV programs throughout the region. whether one will be able to determine retrospectively that the PV penetration had actually prevented a blackout. However, the potential significant loss and blackout

[32] Availability of Dispersed Photovoltaic Resource During the August 14th 2003 Northeast Power Outage, (2004) R. Perez, M. Kmiecik, T. Hoff, C. Herig., S. Letendre, (http://www.asrc.cestm.albany.edu/perez/publications/PV&%20Power%20outage/availability%20of%20PV%20resource-04.pdf)

[33] The Economic Impacts of the August 2003 Blackout, ELCON, (2004)

[34] While the authors do not identify an exact amount of PV that would have been needed in August 2003, they do use the phrase that "at most a few hundred MW" would have been required. For purposes of this analysis we have assumed that 600MW is at or well above the "few hundred" that would have been required.

prevention that could be attributed to PV deployment should be considered as some element of the benefit of a RPS program that encourages distributed PV installations.

Because the authors concluded that a few hundreds of MWs of PV would have been needed to prevent the blackout, Staff and the Commission should consider this benefit when making a determination on expanding the CST-PV program size. Deployment of approximately 50MW, as the program currently envisions, may not be a sufficient quantity of PV to provide adequate blackout prevention.

5. <u>An analysis of job creation and economic development opportunities from RPS investment should reflect the higher jobs per installed MW attributable to PV</u>.

Both the KEMA analysis and the Report include an overview of the jobs and economic development benefit of the RPS. KEMA's analysis as the Report notes focused only on the jobs potential from the Main Tier and did not undertake a specific analysis of the CST. The Report states in FN 79 that "...Staff used information from the Main Tier results and applied it to the Customer Sited Tier in a manner that reflected the higher per megawatt hour cost of the Customer Sited Tier".

What is not clear from the Report's application of that information to CST was whether the Report included the higher jobs per MW ratio of PV. This higher ratio should result in a larger benefit assigned to the CST-PV program element. The Solar Energy Industries Association in its factsheet on net metering states that " PV solar creates more jobs per MW than any other energy source. Each MW manufactured and installed in the US will directly employ 24 people".[35] This finding is reinforced by the growth in employment within PV companies identified within the Report.[36]

The jobs per MW ratio from the KEMA analysis is not readily available but it appears from their report to be lower than the ratio for PV. The higher PV jobs ratio should be used with the economic benefits as shown in the KEMA report then applied to a direct benefit cost ratio calculation for the CST-PV program.

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[35] Solar Energy Industries Association, "Net Metering & Interconnection Standards Pathways to Distributed Generation" (http://www.seia.org/galleries/pdf/SEIA_NMIC_Factsheet.pdf) based on a study by Navigant Consulting. See "Economic Impacts of Extending Federal Solar Tax Credits" (2008) Navigant (http://seia.org/galleries/pdf/Navigant%20Consulting%20Report%209.15.08.pdf).
[36] See Report at p. 107.

6. Conclusion

Throughout the Report's benefit cost analysis of the CST-PV program, estimated costs to install PV systems in New York and the cost elements of the program have been overstated and the benefits discounted. This leads Staff to the erroneous conclusion that PV is too costly and has a benefit/cost ratio less than one (not cost effective). Solar Alliance submits that when more realistic costs for PV are used and the reduced costs associated with a larger and more robust solar program are combined with an accurate assessment of the benefits of distributed PV provides, the benefit/cost ratio of the CST-PV program will exceed one. Based on the discussion above, Staff should be directed to undertake a more in-depth benefit analysis in which all of the benefits of distributed PV are accounted for.

II. THE PV INCENTIVE PROGRAM HAS SUPPORTED THE DEVELOPMENT OF A NASCENT STATEWIDE SOLAR INDUSTRY BUT NEEDS TO INCORPORATE DESIGN CHANGES TO ACCOMMODATE CONTINUED GROWTH.

PV incentives and other market support activity offered through the Customer Sited Tier of the RPS have encouraged the continued maturation of an indigenous New York PV industry. This is reflected in the following specific metrics:

- Over 1,400 systems;
- Nearly 13 MW's of contracted capacity;
- Over 175 qualified installers active in the New York market

It is also reflected in the other important market transformation effects, including the greater familiarity of local code officials with PV technology and safety requirements, the development of more efficient distribution channels, and enhanced consumer awareness and support for solar energy. Indeed, the seemingly unabated demand by New York consumers for PV even in the face of the state's worst economic crisis since the Great Depression highlights the greater mainstreaming of this technology and pent up consumer appetite. It is clear that none of these developments would have occurred in this short timeframe but for the existence of the solar programs implemented by the state authorities in fulfillment of RPS objectives.[37]

[37] As explained by the previously cited Tracking the Sun II analysis of long-term PV cost trends:

However, it is equally clear to those of us in the industry that the current program delivery mechanism has not kept pace with the rapid evolution of the solar marketplace. Refinements must be introduced in the short-term to maintain market momentum within the residential and small commercial segments currently served under the existing program scope; while more sweeping changes need to be introduced to enable the New York market to capture a greater share of the addressable market and produce the full range of benefits at a cost that is affordable to consumers.

Our suggestions for program modifications are summarized in the following chart and described immediately below:

Market segment	Mechanism	Notes
Residential & small commercial <10 kw	Expected performance based buydown (capacity rebate)	Similar to current NYSERDA program with simplified application procedures; 15% adder for in-city projects
Commercial/institutional <80 kw	Fixed performance based incentive (PBI) (10-15 yr.) with declining block structure	15% adder for in-city projects
80 kw – 2,000 kw	Either fixed PBI or PBI with price set by market mechanism (auction); 10-15 year term	Commission and NYSERDA to determine lower threshold limit for market based incentive; 15% adder for in-city projects under PBI
Main Tier RPS for grid connected solar	50 MW solicitation for in-city PV; bidders submit fixed price using contract for differences approach (10-15 year contract)	No explicit lower or upper project size specification

> Trends in non-module costs may be particularly relevant in gauging the impact of state and utility PV programs. Unlike module prices, which are primarily established through national (and even global) markets, non-module costs consist of a variety of cost components that may be more readily affected by local programs – including both deployment programs aimed at increasing demand (and thereby increasing competition and efficiency among installers) as well as more targeted efforts, such as training and education programs. Thus, the fact that non-module costs have fallen over time, at least until 2005, suggests (though does not prove) that state and local PV programs have had some success in driving down the installed cost of PV.

See, Wiser, R., et.al, *Tracking the Sun II: The Installed Cost of Photovoltaics in the U.S. From 1998-2008* (October 2009) at 12.

Utility Tier	Ratebase (utility owned PV) or expensing (contractual or tariffed costs for third party projects)	Subject to level playing field considerations

A. Establish an Incentive Structure More Responsive to Changing Market Conditions.

PV incentive program administrators throughout the country have struggled to keep pace with a very dynamic and evolving regulatory and market landscape for PV. The uncapping of the Federal Investment Tax Credit for residential systems, and sharp reductions in the price of PV modules has made PV more affordable than ever before. Yet, in many states, including New York, the incentive level was allowed to remain at its former level for some time, creating a temporary windfall for consumers and project developers. The result is predictable – a flood of applications and premature exhaustion of available funding.

This situation is neither in the long-term interests of ratepayers nor the solar industry. Where incentive adjustments lag market and regulatory developments, ratepayers are contributing more than necessary to spur solar deployment, and the market is placed in a perpetual boom-bust cycle. In a difficult economic climate, program administrators are forced to go hat-in-hand to regulators or the legislature to replenish depleted program funds to maintain market momentum. From the standpoint of solar developers, visibility into the future scale, incentive level and very existence of the program become conjectural, inhibiting hiring and other significant investment decisions.

Based on our experience with a variety of PV incentive programs implemented across the country, <u>the Solar Alliance would strongly recommend that the PSC and NYSERDA jointly develop a long-term, transparent and self-adjusting incentive mechanism</u>. We refer the Commission to our preceding discussion on cost-benefit analysis for illustrative program designs. As one example, California has implemented a highly successful declining block incentive structure. The chief virtue of the program is that it is market-driven (rather than responsive to a fixed annual budget) – as solar costs come down, blocks are quickly filled and the incentive automatically and transparently adjusts. Program uptake slows until economically viable projects can be developed at this new price point.

B. Transition More Fully to a Performance-Based Incentive Structure

Under the current PV incentive program design, residential and small commercial customers are offered an upfront incentive to help "buy down" the capital cost of the system. Given the capital-intensive nature of PV, this upfront incentive is ideally structured to yield the requisite payback or internal rate of return that will encourage the consumer to deploy behind-the-meter solar as an alternative to grid supply. Meeting these investment criteria is crucial to economic viability and project feasibility.

An upfront incentive offers the surety of revenues to support investment decisions. Unfortunately, upfront incentives also have a number of drawbacks, particularly in the context of programs of any significant scale. As a consequence, states with more robust solar programs are moving to performance-based incentives (PBI). Relative to upfront incentives, a PBI has a number of advantages:

- While upfront incentives reward investment, a PBI encourages energy production. System owners only get paid if the system is generating electricity and contributing to overall supply.
- PBIs inherently incentivize optimal system design and siting. PBIs also encourage active, ongoing maintenance efforts. The long term goals are to generate as many MWh from solar as possible, to encourage higher MWh production per MW, and to promote systems that maximize the time-value of generation.
- PBIs encourage innovation and help drive to the most cost-effective systems. This supports achievement of program deployment targets at the lowest cost to ratepayers.
- PBIs spread the cost of the incentive over a longer time horizon in much the same fashion as a mortgage spreads the cost of a home purchase. In this way, the program costs are not concentrated in the year of project deployment and can achieve greater scale while attenuating short-term rate impacts.

<u>We would suggest that the PV incentive program transition more fully to a form of PBI</u> akin to that now applicable to Main Tier resources. Under this structure, non-residential systems above 50 kw accepted into the program would receive a payment stream over a period of 10-15 years based on metered output. The DPS White Paper seemingly supports this position: "Given the unique nature of CST investments and the fact that

CST costs are fully front-loaded in one year at the start of a project's life this cost stream is a strong potential candidate for securitized financing."[38]

However, given the relatively greater difficulty for residential and small commercial consumers to obtain financing based on the prospect of a longer-term revenue stream, we would recommend that the current program structure be maintained for this class; namely, that incentives continue to be offered at the outset of the project based on capacity, with adjustments accounting for the expected performance of the system (also referred to as "expected performance based buydown").[39]

C. Support Larger-Scale Customer-Sited Projects Up to New York Net Metering Limit through a Competitive Process.

The PSC should take this opportunity to provide essential strategic direction to support a broader diversity of solar applications throughout New York State. One of the hallmarks of a robust state-based solar market is an incentive structure conducive to solar development in homes, businesses and governmental facilities. Incentives must be available across the full spectrum of customer classes and system sizes.

Unfortunately, due to severe funding constraints solar PV incentives offered through the RPS (and previously through the System Benefits Charge) have historically been limited to systems under 80 kw. This fact, coupled with one of the most restrictive net metering policies in the country, has constrained solar energy as an economically viable option for New York's large commercial, industrial and governmental customers. It is critical that the PSC and NYSERDA work collaboratively to correct this situation.[40]

The goal of the solar program should be to maximize the installed solar capacity within the residential and non-residential market segments while minimizing the overall cost of

[38] Report at 90.

[39] The incentive offer in California and New Jersey – the two largest solar markets in the U.S. – may be instructive. In New Jersey, an upfront incentive is available to support projects up to 50 kw as a supplement to revenues that might otherwise be derived from the sale of Solar Renewable Energy Credits. http://www.njcleanenergy.com/renewable-energy/programs/renewable-energy-incentive-program/renewable-energy-incentive-program-cust In California, the current cut-off for an upfront Expected Performance Based Incentive is 50 kw; however, this threshold is due to come down to 30 kw beginning January 1, 2010. California Solar Initiative, Program Handbook (July 2009) at 35.

[40] Residential systems make up 71% of all installed PV capacity funded through the NYSERDA rebate program to date, while commercial and industrial applications represent a 29% share. *New York Energy $mart Program Quarterly Evaluation Report* (November 2007) at Table 5-7. California and New Jersey are the United States' two leading solar PV markets. In these states, commercial installations represent well over half of all solar capacity installed to date.

doing so. To that end, the Solar Alliance recommends that the PSC require solar program administrators to allocate funding to the residential and non-residential market segments in approximately the same proportion as the market segment contributes to total utility retail electric revenue. Unused incentive funds within each market segment should carry forward into future years within the respective market segment; however the program administrator should retain flexibility to move unused funding to other market segments if market conditions warrant. Significant adjustments should be implemented only after public notice and opportunity for comment.

The Solar Alliance recommends that the incentive structure for the currently un-served CST-PV market segment (80kw – 2,000kw) take the form of a combination of: 1) a fixed price PBI and 2) a PBI with price set by market mechanism (auction). The Commission, in consultation with NYSERDA, should set the upper size limit for fixed price PBI eligibility, with incentives for the remainder of the market segment allocated on a competitive basis.

With respect to a Commission-sanctioned auction process, one approach with considerable promise is NYSERDA's recently issued Program Opportunity Notice 1686. Under this structure, developers are asked to bid their required capacity based incentive. Bids are rank ordered and paid based their required capacity based incentive. Assuming robust competition for these scarce incentive dollars, this will assure that ratepayers are paying no more than necessary to procure solar resources. In the vein of our comments in the preceding section, rather than a capacity-based buydown incentive design, a more appropriate structure would be one based on actual kwh's generated.[41]

D. The PV Incentive Reservation Process Should be Streamlined.

The current rebate reservation process must be streamlined and made more predictable and transparent. Rebates should be available on a first-come, first-served basis to projects meeting threshold eligibility criteria and development milestones. The detailed design review embodied in the current Program Opportunity Notice process, while appropriate to an infant industry, is no longer necessary given the current state of maturation of the New York solar installer base and could impede realization of more ambitious deployment targets going forward.

[41] We recognize that PON 1686 was designed to meet the specifications of the federal stimulus program; namely, that funding flow to eligible projects by 2012. While this would have precluded a performance-based incentive for the specific purposes of PON 1686, similar strictures would not apply to RPS funded projects.

E. PV Can Play an Important Role in Redressing Perceived Inequities in the Distribution of Renewable Resource Development.

1. Distributed PV provides unique locational benefits which are not explicitly targeted or maximized under the current statewide incentive program structure.

As enumerated in the Report, and further documented in Section I of these comments, PV offers numerous benefits for the hosting customer, for the utility and other ratepayers, and for New Yorkers at large. These benefits are especially pronounced when PV is located within congested, high cost areas of the grid. This benefit flow results from distributed PV's unique attributes:

- PV output closely correlates with peak demand and therefore displaces a higher percentage of the most expensive energy and capacity than other RPS-eligible technologies;
- PV is modular and capable of being installed in increments more precisely aligned with distribution system needs;
- Sites capable of supporting PV are ubiquitous, even in heavily populated urban areas like New York City and its environs;
- Rooftop PV does not require environmental or zoning approval and rarely if ever encounters local opposition that can stymie timely siting and project development for other renewable resources;
- PV deployment can be strategically located to buttress otherwise stressed sections of the distribution network.

Under the current statewide solar incentive program framework these locational benefits are not explicitly recognized or targeted. Rather, incentive levels are broadly set on a statewide basis. While PV host customers in the downstate region typically derive greater energy savings given the higher cost of grid supply relative to other parts of the state, given the higher cost of doing business in New York generally they are also exposed to higher installed costs.[42] The net effect appears to be that a greater concentration of systems is being installed in downstate markets outside New York

[42] *See generally,* City University of New York, *New York City's Solar Energy Future* (January 2007) at 29 (finding installed cost of solar energy consistently higher than rest of state over 2003-6 study period).

City.[43] In any event, this development pattern is not the result of a conscious policy or program goal. It would be our recommendation to make this an explicit factor in program design and future incentive delivery.

2. Any effort to redress perceived inequities in renewable resource development must include the greater deployment of distributed PV.

Over the course of the Commission's RPS Technical Conference, New York City, Consolidated Edison and members of the Commission have expressed concerns regarding the disparity between those funding the RPS program versus those directly benefitting from renewable development in their region. More specifically, various New York City-based stakeholders have argued that they are contributing a disproportionate share of the overall RPS, while most of the actual renewable resource development is occurring elsewhere.[44]

While the Solar Alliance takes no position on this issue, it is our firm belief that any attempt to correct perceived geographic inequities by redirecting resource development must include greater investment in distributed PV. For the reasons indicated above, distributed PV provides the highest value output of any RPS-eligible technology and is readily adaptable to a dense urban environment.

3. Consolidated Edison can play a number of constructive roles with regard to a geographically targeted PV program.

In our November 2008 comments, we identified a number of ways in which the distribution utility can leverage its comparative strengths to foster high value PV development within its service territory. These advantages include, but are not limited to: the utility's customer relationships, understanding of the distribution network, billing infrastructure, and capital strength. While we understand the broader and perhaps more controversial question of whether New York utilities should be permitted to own and ratebase renewable generation assets is also squarely before the Commission in this proceeding,[45] we believe the Commission should go at least as far as sanctioning a more narrow and targeted utility facilitation role in the downstate region. To summarize, we

[43] RPS Technical Conference, Presentation of Janet Joseph, NYSERDA Director of Clean Energy Research and Market Development November 12, 2009.
[44] RPS Technical Conference, October 28, 2009, Remarks of Joseph Oates, Consolidated Edison; James Gallagher, New York City Economic Development Corporation.
[45] Our perspective on this topic is provided in the following section.

believe the Commission should consider directing utilities to perform the following functions:

- Identifying areas of the distribution system that require upgrades and are amenable to a PV solution.
- Determining segments of network system that can accommodate significant penetration of PV and making this information more readily available to the public.
- Assisting in marketing of PV program to customers.
- Facilitating fast track interconnection
- Providing additional incentive (beyond that generally available on a statewide basis) in recognition of the distribution system deferral benefits and other ancillary services PV may provide.
- Offering on-bill financing for solar PV.

We refer the Commission to our November 2008 comments for a fuller discussion of each of the above points.

4. Recommendations

Based on these considerations, the Solar Alliance recommends that the Commission:

- Establish "soft targets" of 25-30% for New York City within the current CST framework. PV capacity earmarked for development in New York City and its environs would be additive to existing base level effort
- To foster this development, NYSERDA should consider offering a 15% incentive adder for New York City in recognition of the higher cost of doing business here, while taking into account any offsetting advantages such as the recently-enacted 35% property tax abatement.[46]
- NYSERDA, in conjunction with Consolidated Edison, should conduct aggressive market and barrier-busting activities to promote PV development in the region, including coordinating activities with the New York City municipal efforts to create "Solar Enterprise Zones".
- To prevent a potential stranding of these incentive funds should the desired level of market activity not materialize in the anticipated timeframe, NYSERDA should

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[46] A11202, (enacted August 8, 2008). The law allows for an abatement of property taxes for the installation of solar energy equipment on eligible properties in New York City. Systems installed over the next two years are eligible for an abatement of 35% of system costs up to $250,000; for systems installed thereafter, the abatement drops to 20% of system costs.

retain the flexibility to periodically rededicate uncommitted PV incentive funds to other parts of the state showing robust growth.

- The Commission should examine the merits of a separate geographically targeted solicitation seeking up to 50 MW of grid-connected distributed solar PV within the Main Tier of the RPS. The Commission should consider a Contracts for Differences (CFD) approach (15 year minimum term) to compensating winning bidders. Although there are variations, a simple CFD in this context would involve NYSERDA paying the difference between the spot market price obtained by a generation provider and an agreed-upon price between the generation provider and NYSERDA.[47]

F. The PSC Should Enable Utilities to Own and Ratebase Solar Generation Assets on a Limited and Conditional Basis.

The Staff Report categorically rejects the idea of utilities assuming an ownership stake in the deployment of PV under a proposed Utility Sited Tier. As proposed, the Utility Sited Tier would encourage small utility-scale projects at strategic locations throughout the distribution network. The DPS Staff argues that "The Utility Sited Tier costs are inherently higher due to the need to pay the participant cost of $8/watt instead of an incentive cost of $3/watt or less, and a utility profit or "return" on the investment that includes income taxes. Given the Commission's policies on Utility ownership of generation and the substantially higher unit cost of a Utility Sited Tier, this option is not recommended."[48] While we concur that utility ownership requires rate payers to assume the full cost[49] of project development and does not, to the same extent as other development models such as a power purchase agreement (PPA) structure or Feed-in Tariffs with third party developers, leverage private financing, we do believe that in the context of the New York PV program portfolio there is a place for utility ownership.

We would agree with DPS Staff that where there is a potential overlap with the CST program offering, there should be no utility ownership. Further, this segment is already highly competitive. We would further agree that in this context the utility role should be

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[47] *See* ORDER APPROVING IMPLEMENTATION PLAN, ADOPTING CLARIFICATIONS, AND MODIFYING ENVIRONMENTAL DISCLOSURE PROGRAM Issued and Effective, April 15, 2005 at 14.

[48] DPS Staff White Paper at 29.

[49] For the reasons stated in Section I of these comments, we believe that the Report substantially overstates the installed cost of PV. This is particularly true in the context of large-scale development where there are economies of scale on an order of 25% or more.

confined to one of facilitating customer-owned solar and removing structural barriers that inhibit this development.

However, there is currently no program offering in the greater than 80 kw market, so this is a bit of a non sequitur. Within the currently underserved solar market segments; i.e., market segments outside customer-sited PV above 80 kw, we envision a more robust utility role. For distributed power plants (i.e., small scale systems connected directly to the distribution grid) the Commission should experiment with a range of ownership and business development models, including utility ownership, subject to level playing field and market concentration concerns.

A fuller discussion of the Solar Alliance's policy position on utility ownership of solar generation is provided as Attachment B.

III. CONCLUSION

WHEREFORE, the Solar Alliance respectfully requests the Commission to direct DPS Staff to reassess the costs and benefits of PV by correcting for the deficiencies noted herein. Further, the Solar Alliance urges the Commission to extend and expand the RPS incentive program for PV consistent with these comments.

Respectfully submitted,

Carrie Cullen-Hitt, President
Scituate, MA
November 19, 2009

On Behalf of
THE SOLAR ALLIANCE

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ATTACHMENTS

ATTACHMENT A

Energy and Capacity Valuation of Photovoltaic Power Generation in New York

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for the Solar Alliance and the New York Solar Energy Industry Association

March, 2008.

Executive Summary

This initial investigation in the value of photovoltaic (PV) power generation for New York focuses on the value to utilities. Specifically, the report asks whether PV net-metering constitutes a loss to the utilities which would negatively affect their rate payers.

The value of customer-sited PV generation to a utility includes generation-level energy and capacity, as well as environmental compliance benefits, fuel price hedge protection, and location specific-transmission and distribution (T&D) and loss savings benefits.

Results show that, because of the strong coincidence that exists between peak demand and solar resource availability both downstate and upstate, the generation energy and capacity value of PV alone amount to 75% of the revenue loss utilities would incur from their net-metered customers. It is very likely that the other value elements: environmental compliance, fuel price risk mitigation, and localized T&D/loss savings, which will be quantified in detail in a subsequent study, will bridge the remaining 25% gap[1], making distributed PV a net benefit to New York utilities, and by extension to their rate payers.

Introduction

What is the value of distributed photovoltaics (PV)? The answer is driven by the perspective of the one who is asking the question [2, 4, 5]. Table 1 conceptually illustrates how to incorporate perspective for a program that is designed to incentivize

[1] a modest carbon fee of $40 per metric ton alone would bridge much of this gap

individual owners to invest in PV. The table suggests that there are really three questions, not just one question.

1. Individual customers (i.e., potential system owners) want to know if there is sufficient economic incentive to invest; this occurs when incentives plus utility bill savings plus tax effects exceed PV system cost

2. Utilities want to know if the cost savings associated with the addition of PV to the utility grid offset the reduced revenue from lower utility bill sales

3. Constituents (ratepayers and taxpayers) want to know if the benefits to them exceed the cost of the direct incentive program and tax effects

Table 1
Effect of Perspective on Question: What is the Value of PV?

	System Owners	**Utility**	**Constituents**
Equipment	cost		
Incentives	benefit		cost
Utility Bill	benefit	cost	
Tax Effects	benefit		cost
Utility Cost Savings		benefit	
Constituent Benefits			benefit
Net Benefit	???	???	???

Objective

As an initial step towards a comprehensive New York State PV valuation study, the objective of this project is to assemble and contextualize the key underlying facts central to the utility's perspective. Some of the key benefits to the utility include energy production value, generation capacity value, transmission and distribution (T&D) system capacity deferral value, loss savings, environmental value, and fuel price hedge protection [3]. This initial work will focus on the energy production value and the generation capacity value.

Subsequent phases of this work should address the comprehensive value to all parties involved. In particular, the following benefits to the utility need to be evaluated:

- T&D capacity deferral value
- Loss savings

- Environmental compliance value
- Fuel price hedge protection

In addition, the benefits to ratepayers need to be addressed, including:

- Long-term, system-wide rate protection [1]
- Environmental health benefits [1]
- Business development opportunities (job and business creation) [1]
- Use of in-state resource and reduction of state imports
- Power grid security enhancement
- Disaster recovery [3]

While this study focuses on the generation energy and capacity value to the utility, a preliminary discussion of the value of the other benefits to the utility and ratepayers is provided in the Appendix 2.

Value to Utility

Energy Value

The value of PV-generated energy was quantified at the wholesale level using the location-based-marginal energy generation pricing administered by NYISO for the year 2007 for three selected regions in the state of New York: Western, Capital and Long Island (see Figure 1) while considering three PV geometry configurations: South-facing tilted (30° slope), southwest-facing tilted (30° slope), and horizontal.

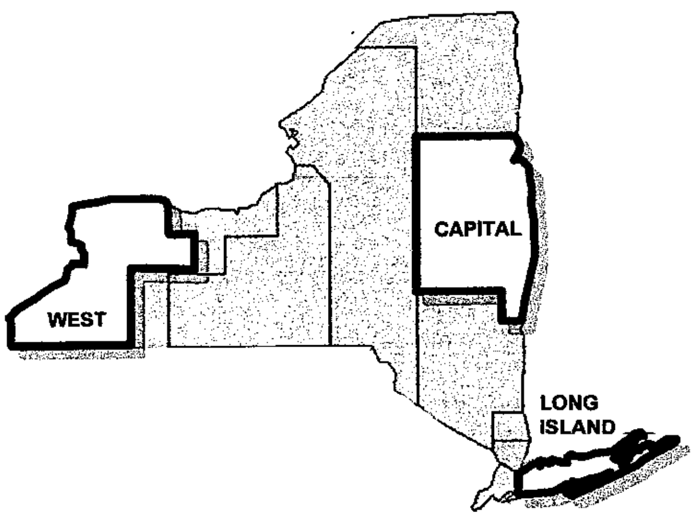

Figure 1: Selected NYISO Electrical regions

The regions were selected to represent the electrical and climatic landscape of New York State, from the Long Island load pocket (most expensive wholesale energy) to the western frontier (typically the least expensive rates), with the capital region at a crossroads.

The PV configurations were selected to represent optimal energy gain (south-facing tilt), optimal summer peak time match (southwest-facing tilt) and least-cost commercial applications (horizontal).

PV Energy Yield: Table 2 summarizes the energy production of all selected PV configurations in each region in 2007.

TABLE 2
PV Output in kWh Normalized to one $kWac_{ptc}$[2] Systems

	PV Geometry		
Location	South 30° Tilt	Southest 30° Tilt	Horizontal
Long Island	1,652	1,560	1,415
Capital	1,593	1,497	1,360
West	1,457	1,388	1,288

Overall the energy yield in Long Island was roughly 15% higher than in the west and 6% higher than in the Capital region. South-facing tilted installations produce 10-13% more energy than a horizontal installations, while a southwest orientation still results in a 6-9% gain over the horizontal.

Wholesale Energy Value: Table 3 compares the wholesale value of PV energy when sold at the location-based marginal pricing (LBMP) and compares this value to the average LBMP traded in each considered region. The table includes both year-around and summer (June to September) values.

TABLE 3
LBMP Value of PV Energy vs. Average LBMP pricing ($/MWh)

ALL YEAR	PV Geometry			AVERAGE
Location	South 30° Tilt	Southest 30° Tilt	Horizontal	PRICE
Long Island	$ 106	$ 109	$ 107	$ 93
Capital	$ 78	$ 78	$ 78	$ 73
West	$ 61	$ 62	$ 61	$ 55
SUMMER	PV Geometry			AVERAGE
Location	South 30° Tilt	Southest 30° Tilt	Horizontal	PRICE
Long Island	$ 117	$ 123	$ 115	$ 91
Capital	$ 80	$ 81	$ 79	$ 69
West	$ 72	$ 73	$ 71	$ 60

[2] AC output at PTC conditions: 20 degrees C ambient and 1000 Watts per m^2 solar irradiance. The AC-PTC rating is typically 70%-80% of the dc system rating at standard test conditions (stc).

On a year-around basis, the PV MWh are worth more than the average traded price -- 7%, 11% and 15%, respectively for the Capital, West and Long Island regions. In summer the solar premium is higher, respectively 16%, 20% and 30% for the three regions. The southwest orientation yields a slightly higher per MWh premium, reaching 35% in summer for Long Island -- \$123/Mwh against a \$91/Mwh average traded price.

Congestion Pricing: In addition to the LBMP, the NYISO congestion pricing data reflect the value of producing the energy locally over importing it in the considered region. Congestion pricing data are summarized in Table 4. Congestion pricing represents the penalty imposed on out-of-zone generators (i.e., not imposed on PV that produces energy locally). Data show congestion pricing is a significant issue in the Long Island load pocket. There, the local congestion premium garnered by PV is considerably higher than the mean local congestion premium, exceeding 100% for southwest-oriented systems in summer.

TABLE 4
Avoided Congestion Pricing from Local PV Generation (\$/MWh)

ALL YEAR	PV Geometry			AVERAGE PRICE
Location	South 30° Tilt	Southest 30° Tilt	Horizontal	
Long Island	$ (32)	$ (34)	$ (32)	$ (24)
Capital	$ (7)	$ (7)	$ (7)	$ (8)
West	$ (2)	$ (2)	$ (2)	$ (2)
SUMMER	PV Geometry			AVERAGE PRICE
Location	South 30° Tilt	Southest 30° Tilt	Horizontal	
Long Island	$ (35)	$ (39)	$ (34)	$ (19)
Capital	$ (1)	$ (2)	$ (1)	$ (1)
West	$ -	$ -	$ -	$ -

Capacity Value

Quantifying Capacity Credit: We used two metrics that were recently recommended by a panel of utility, solar industry and government professionals [7]. The two metrics are the Effective Load Carrying Capability (ELCC) and the Solar Load Control Capacity (SLC). Both metrics are described in detail in Appendix 1. The ELCC represents the increase in capacity available on a local grid and that is attributable to the added PV generation without increasing the grid's loss of load risk. The SLC reflects the synergy that exists between load control (e.g., demand response) and PV generation. The metric is an answer to the question: Given a certain amount of Demand Response (DR) available to a utility, how much more guaranteed load reduction is possible when PV is deployed?

Table 5 reports the ELCC and SLC of PV for grid penetration ranging from 2% to 20% as derived from the analysis of 2007 PV generation and load data. The table also reports the amount of demand response in MWh needed to achieve 100% PV capacity credit and the amount of DR that would have been necessary to achieve the same objective without PV. Capacity credit results are further summarized in Figure 2 for the southwest facing orientation, using a composite of the two metrics.

TABLE 5
PV Capacity Credit (%) as quantified by the ELCC and SLC Metrics and DR (MWh) required to firmly displace peak with, and without PV

	PV PENETRATION	2%	5%	10%	15%	20%
Capital	ELCC South 30	71%	62%	59%	41%	31%
Capital	ELCC Southwest 30	84%	79%	70%	50%	39%
Capital	ELCC Horizontal	67%	60%	57%	42%	32%
Long Island	ELCC South 30	53%	53%	53%	43%	32%
Long Island	ELCC Southwest 30	70%	70%	70%	48%	38%
Long Island	ELCC Horizontal	51%	51%	51%	44%	33%
West	ELCC South 30	87%	81%	74%	59%	44%
West	ELCC Southwest 30	90%	90%	74%	59%	44%
West	ELCC Horizontal	81%	75%	73%	59%	44%
Capital	SLC South 30	75%	65%	56%	44%	40%
Capital	SLC Southwest 30	85%	82%	65%	57%	45%
Capital	SLC Horizontal	70%	63%	60%	45%	41%
Long Island	SLC South 30	55%	53%	52%	48%	46%
Long Island	SLC Southwest 30	72%	71%	60%	55%	53%
Long Island	SLC Horizontal	55%	54%	53%	49%	45%
West	SLC South 30	87%	85%	74%	55%	33%
West	SLC Southwest 30	88%	88%	75%	57%	34%
West	SLC Horizontal	83%	82%	69%	52%	32%
Capital	MWh DR South 30	26	86	573	2,508	9,035
Capital	MWh DR Southwest 30	12	42	355	1,510	7,081
Capital	MWh DR Horizontal	29	100	585	2,376	8,839
Long Island	MWh DR South 30	63	246	1,028	2,711	7,330
Long Island	MWh DR Southwest 30	32	120	645	1,705	4,639
Long Island	MWh DR Horizontal	70	258	1,058	2,713	7,065
West	MWh DR South 30	15	51	476	4,931	32,095
West	MWh DR Southwest 30	10	39	459	4,755	31,906
West	MWh DR Horizontal	28	90	646	5,233	32,330
Capital	MWh DR No PV	117	828	5,566	18,949	44,901
Long Island	MWh DR No PV	198	1,100	6,602	22,264	51,941
West	MWh DR No PV	278	2,481	13,684	40,590	109,465

Results in Table 5 and Figure 2 show that the capacity credit of PV in the State of New York is high. The capacity credit decreases with penetration[3], but remains significantly higher than the resource's capacity factor at high penetration (note that 20% penetration represents well over 6,000 MW of PV in New York). The amount of demand response necessary to guaranty firm peak reduction with PV is a small fraction of the amount that would be necessary to achieve the same without PV – e.g., for Long Island at 10% penetration the DR requirement with southwest facing PV would be 645 MWh; achieving the same objective without PV would require 10 times more DR.

Interestingly the capacity credit extracted from the 2007 load and PV output data is found to be higher for the upstate regions than downstate, at least a low penetration. At high

[3] The reason for this decrease is that, as PV penetration exceeds the size required to shave the highest demand peaks which are highly correlated with the solar resource, PV must meet secondary peaks and non peak loads which are less correlated with solar gain.

penetration Long Island retains a higher capacity credit. This upstate trend is consistent with a previous observation by the authors that compared the evolution of effective capacity nationwide from the late 1980's to the early 2000's [8]. A general increase in PV capacity for northern utilities had been noted possibly traceable to increased cooling demand from higher technology use, as well as a gradual winter and summer temperature increase likely linked to intensifying global warming. The West and Capital regions are solidly summer peaking with 2007 summer to winter peak ratios of 1.15 and 1.20 respectively. The Long Island region is highly summer peaking with a 2007 summer-winter ratio of 1.50 -- explaining the greater resilience of capacity credit at high penetration (see note 2 above).

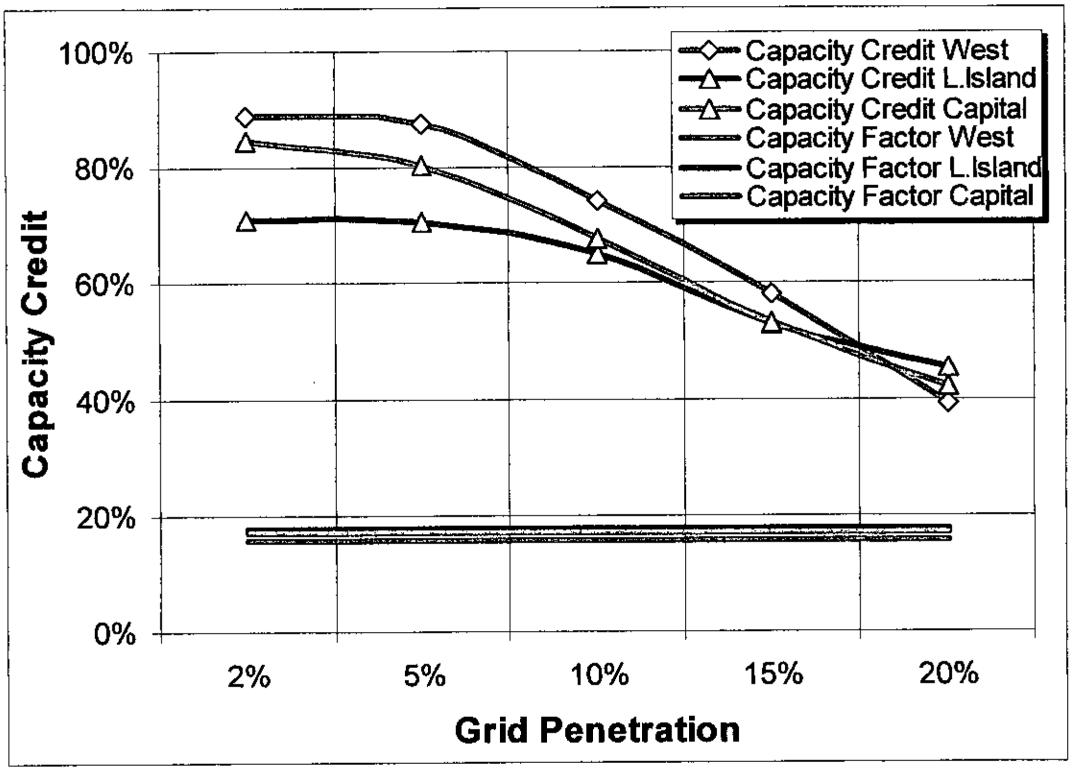

Figure 2: Composite capacity Credit[4] for the southwest-facing tilted PV configuration, compared to the resource's capacity factor[5]

The main reasons for the upstate downstate difference, however, are the demand load shapes and peak-day solar conditions. Figures 3, 4 and 5 display the solar resource for all PV configurations and load shape on peak day for the West, Capital and Long Island regions respectively. The figures also show the load impact of a 10% PV penetration for southwest facing installations. The upstate peaks occur earlier in the day and have less of an evening shoulder (i.e., more commercial cooling relative to residential cooling). Also,

[4] The composite capacity credit is the mean of the ELCC and SLC metrics
[5] The capacity factor is the mean output divided by the rated capacity

while the solar resource was significant during the downstate peak day (August 8), it was ideal during the upstate peak day (August 2).

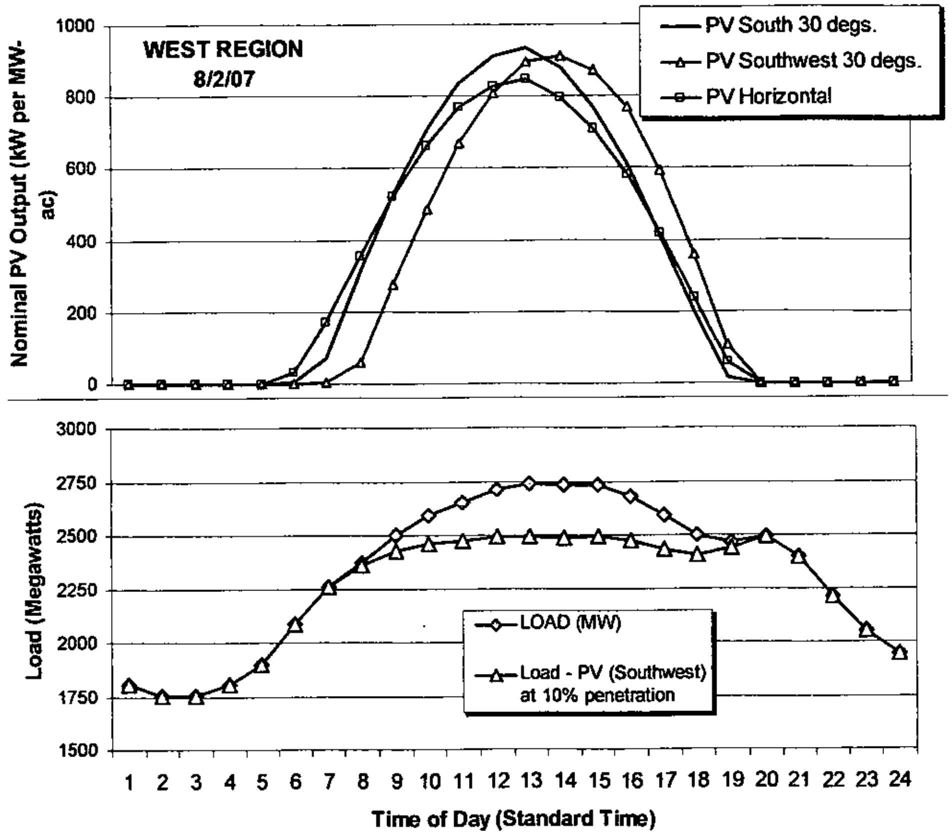

Figure 3: Peak day PV resource and load in the West region

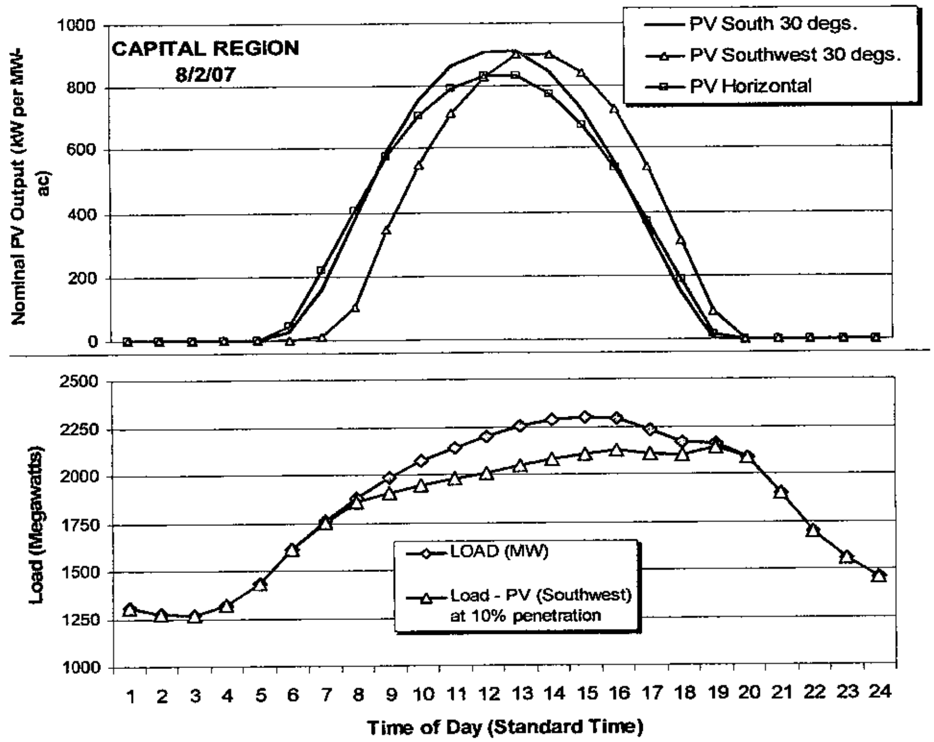

Figure 3: Peak day PV resource and load in the Capital region

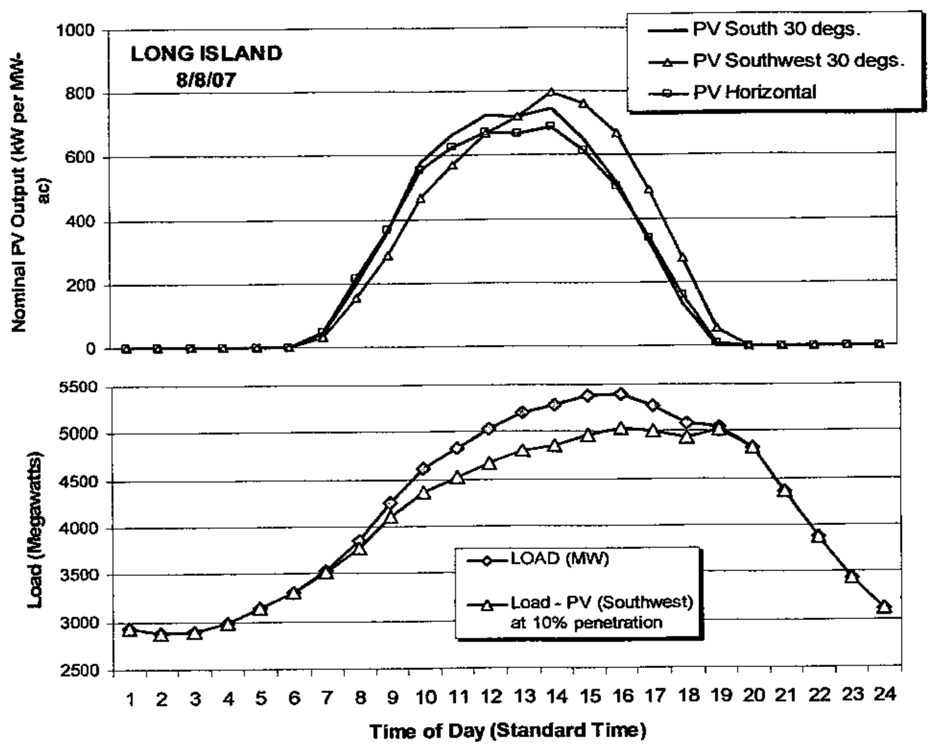

Figure 4: Peak day PV resource and load in the Long Island region

Capacity value: While capacity is not a directly traded commodity, its value is quantifiable trough DR programs, that, in effect provide up to $100 per kW per year for stand-by capacity [e.g., 6] that may, or may not be called upon. Another gauge of capacity is demand-based tarrification offered to large utility customers that is valued at $180/kW per year upstate (National Grid) and as high as $250/kW per year downstate (ConEdison).

In the case of DR, it as been demonstrated that the addition of PV on the grid firmly diminishes the need for DR and saves money to the DR program administrator, commensurately with the capacity credit of the solar resource -- a windfall that PV does not currently capture. The 2007 data analyzed in this study and presented in Table 5 fully confirm this assertion.

Taking the smaller DR number of $100/kW as a gauge of regional capacity value downstate, the 70% capacity credit of PV would be worth an additional $45 for each PV-generated MWh – a value the wholesale level that is not currently captured by PV but directly benefits the utilities.

Conclusion

The sum of the wholesale energy and capacity value of PV equals $0.109/kWh energy + $0.045/kWh capacity = $0.154/kWh in the Long Island region. The net metered-residential customer retail rates in that region currently equals about $0.20/kWh. As a result, these two values alone amount to over three-quarters of the net metered-residential customer retail rates in that region. The addition of loss savings, T&D system benefits, environmental compliance value, and fuel risk mitigation benefits unique to PV will result in additional cost-savings to the utility and thus increase the value from the utility's perspective.

Thus, the answer to the question, "What is the value of PV," from the utility perspective is likely to be that **New York's utilities will have a net benefit from the net-metered deployment of PV in their service territories.**

Next Steps

The next steps in addressing the comprehensive value of PV include (1) calculating the other benefits to the utility, (2) evaluating the economics from the system owner's perspective, and (3) calculating the benefits to all the ratepayers.

References

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3. Hoff, T. E, et. al. (2006). The Value of Distributed Photovoltaics to Austin Energy and the City of Austin. SOLICITATION NUMBER: SL04300013.March 17, 2006. http://www.austinenergy.com/About%20Us/Newsroom/Reports/PV-ValueReport.pdf

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6. Brown, S. R., (2007): DR, DG and Storage. Comments To NYISO Symposium. The Future Is Now: Energy Efficiency, Demand Response and Advanced Metering. June 27, 2007.

7. Perez, R., M. Taylor, T. Hoff, and J. P. Ross, (2008): Moving Toward Consensus on a Photovoltaic Generation Capacity Valuation Methodology. USDOE Technical Report on Contract DE-FC36-07GO17036

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APPENDIX 1 -- EFFECTIVE CAPACITY METRICS

Effective Load Carrying Capability (ELCC)

The ELCC metric was introduced by Garver in 1966[6] and has been used mainly by "island" utilities before the strengthening of continental/regional interconnectivity. The method was applied at Pacific Gas and Electric Company[7]. The ELCC of a power plant represents its ability to increase the total generation capacity of a local grid (e.g., a contiguous utility's service territory) without increasing its loss of load probability. The ELCC is determined by calculating the loss of load probability (LOLP) for two resources. The first resource is the actual resource with its time-varying output. The second resource is an "equivalent" resource with a constant output. The ELCC may be graphically visualized on a load duration curve plot. The example presented in figure 1 -- using load data from Rochester Gas and Electric and a PV penetration X/L = 20% (see case studies below) -- shows the utility load duration curve with and without PV, and also shows the load duration curve obtained with a constant output generator with an ELCC capacity calculated at 145 MW for this case study (see quantitative case studies below).

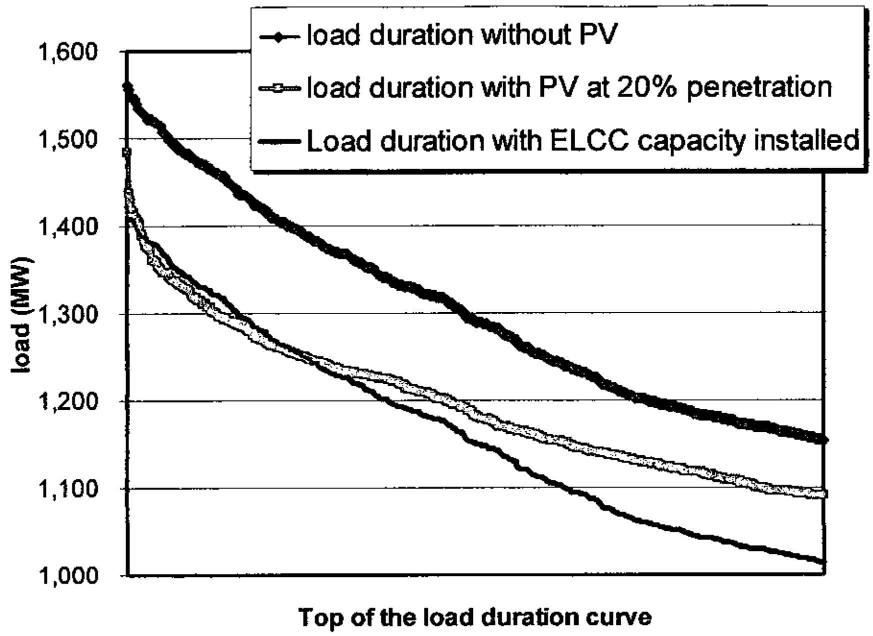

Figure 1. Comparing Load duration curves with and without PV to equivalent load duration curve assuming a constant output generator with an ELCC capacity. The above example is given for Rochester Gas and Electric (peak load = 1561 MW) and a PV penetration of 20% (312 MW). The ELCC calculated for this case figure is 47% (146 MW).

[6] Garver, L. L., (1966): Effective Load carrying Capability of Generating Units. IEEE Transactions, Power Apparatus and Systems. Vol. Pas-85, no. 8

[7] T. Hoff, "Calculating Photovoltaics' Value: A Utility Perspective," IEEE Transactions on Energy Conversion 3: 491-495 (September 1988).

It has also been shown that ELCC could be estimated from simple proxy measurements of local characteristics, such as a utility's summer-to-winter peak load ratio (see Fig. 2).

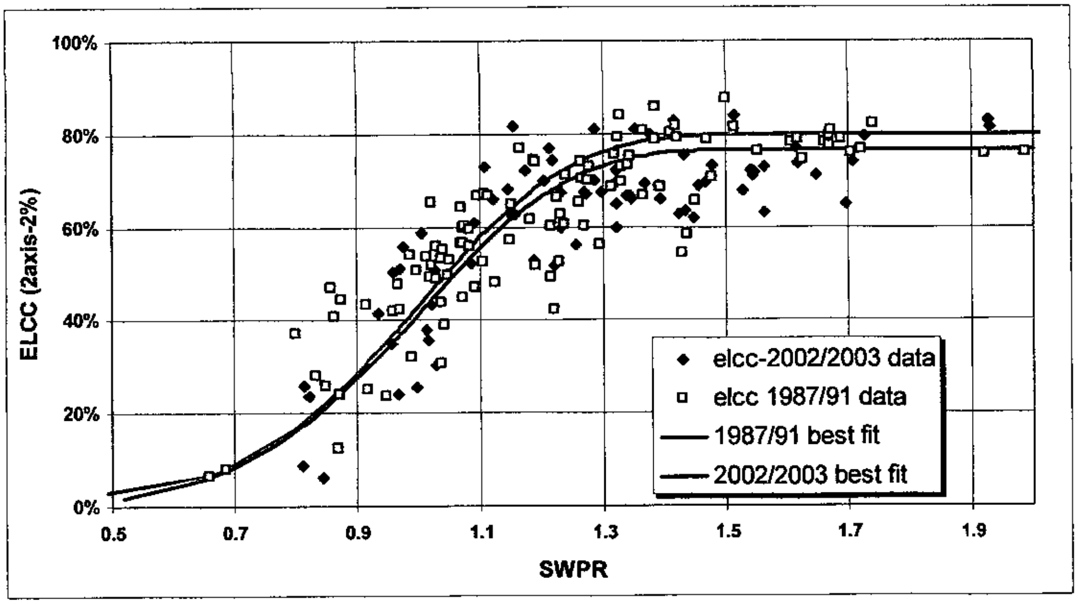

Figure 2. Relationship between ELCC and a utility's (or substation's) summer-to-winter peak load ratio.

Solar-Load-Control-based Capacity (SLC)

This metric answers the question: Given a certain amount of demand response available to a utility, how much more guaranteed load reduction is possible if PV is deployed?

It is illustrated in Figure 5.

Given a penetration $p = X / L$, the effective capacity is given by

$$SLC = (X - Y) / X \tag{6}$$

Where Y is the amount of load reduction achieved in the absence of PV with the same cumulative amount load control needed to guaranty a load reduction equal to X with PV

As above, this metric accounts directly for grid penetration.

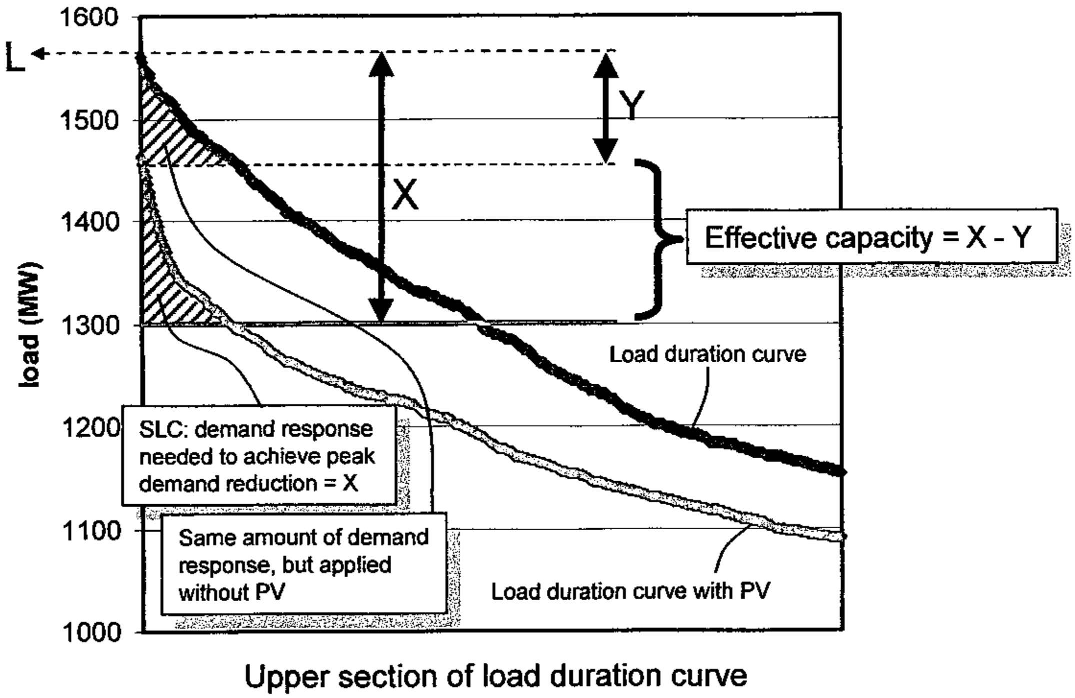

Figure 3. The same amount of demand response load management can be added to mitigate peak load with or without PV present, resulting respectively in load reduction to the Y' and X threshold lines. The effective capacity of PV is measured by its ability to reduce peak loading from the blue to the red threshold. The above illustration is for Rochester gas and Electric with a 260 MW installed PV capacity (SW facing).

Solar Alliance Principles for Utility Ownership of PV Assets
October 22, 2009

The Solar Alliance (SA) is dedicated to accelerating the deployment of solar energy in the United States. Our goal is to provide balanced and sound technical and policy expertise in support of the delivery of solar energy to all markets: residential, commercial, government, and utility customers. The extension of the federal investment tax credit (ITC) and its expanded applicability to include investor-owned utilities is fast becoming a significant factor in increasing utility interest in solar and driving market transformation. Additional utility commitment is encouraged by renewable portfolio standards, impending climate change policy, declining technology costs and widespread public support for solar.

General principles for utility ownership of PV assets:

- Solar policies and regulations that encourage a diversity of participants and market segments produce the best outcomes for ratepayers and market participants alike.
- Utility solar asset ownership should not foreclose non-utility and customer ownership options in any market segment.
- Regulatory decisions to allow utility solar asset ownership and cost recovery of solar investments from ratepayers should be made in an open, transparent manner that compares the relative benefits and lifecycle costs of all ownership options, as well as the costs of utility ownership versus contractual solar power purchases.
- Rate-supported utility solar asset ownership should not be allowed to monopolize any particular market segment. To this end, regulators should continuously monitor the relative percentage of utility-owned solar versus third-party and customer-owned solar.
- Utilities should be encouraged to offer pilot programs to explore various roles, including asset ownership and others, for their involvement in meeting the solar policy goals of the State.

The SA welcomes the involvement of utilities[1] as customers and facilitators of widespread adoption of PV. Utilities will likely be major purchasers of systems, components, renewable bundled power and SRECs from the solar industry. There are several appropriate ways for

[1] The definition of utilities as used hereafter does not include competitive affiliates of utility holding companies but is limited to utilities whose investments are directly supported through some means of rate recovery.

utilities to participate in solar. The Solar Alliance believes that state solar policies and regulations must encourage development of all market segments. Utility roles in the solar market will vary across these segments.

Market segments and related policies are as follows:

1.Utility Scale

Utility scale power plants (20 MW plus) are defined here to be those where connection may be to the transmission system and locations require system planning at the utility level to ensure that the plants are integrated seamlessly into the grid.

Utilities buy solar power and systems to meet RPS requirements and to provide cost effective wholesale power within an overall generation portfolio. For wholesale procurement the SA recommends that purchases be made in an open, transparent manner[2]. Utilities should consider bundled power purchases, system ownership and other options in order to select the most cost effective approach that promotes competition while accounting for total lifecycle costs. Where the near term amount of solar to be supported has been limited by state policy makers (such as with an RPS), there should be a conscious decision made to ensure that utility purchases of utility-scale solar power do not preclude participation of non utility participants in a distributed solar market (including wholesale and retail distributed generation.)

2. Wholesale Distributed Generation Power Plants

Wholesale Distributed Generation installations are solar plants connected directly into the distribution grid. Although these PV systems are normally in the range of 1-20 MW, they may also be smaller systems, located on customer property but connected directly to the utility grid to service all ratepayers rather than just reducing the local electrical usage at the site.

The development, financing, design, and construction of wholesale distributed power plants should be considered to be a competitive market segment. The following is a hierarchy of appropriate activity for utilities interested in encouraging the development of or owning distributed power plants:

1. Financing solar plants through use of utilities' ability to recover costs over 20 to 30 years.

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[2] Individual contract details may of course be kept confidential to protect individual company proprietary information.

2. Contracting for EPC services from non-utility contractors using a fair, transparent procurement process.
3. Purchasing equipment from independent suppliers and installing systems with utility labor.

In each case, before an allowance is made to approve cost recovery through rates, the burden of proof should be on the utility to show that non-utility resources could not be used to more effectively meet the particular need.

Where systems are deployed that provide electricity directly to a utility, ratepayers are best served by providing for competition between utility and third-party development and/or ownership. The competitive process should include comparing the ratepayer impact of a third party providing electricity under a long-term power purchase agreement (PPA) with the lifetime per-kWh cost of energy of a system owned by the utility.

In cases where a utility proposes to construct projects using internal resources, the full costs of deployment, including project management, should be used in comparing ratepayer impact to the costs of projects developed by third parties and sold to a utility.

3. Retail Distributed Generation Solar at Customer Locations

Retail Distributed Generation installations are defined here as those where PV connections are behind the customer meter and the solar power reduces electrical usage at the site.

This market segment is fully competitive and direct utility participation should be limited.. Utilities may directly support customer PV installations through rebates, performance-based incentives (PBIs), PPAs or loans. There may be select cases where structural deficiencies in the market may be addressed by the appropriate involvement of utilities. For example, it may be appropriate for one or more utilities to underwrite customer contracts in order for an immature market (where financing is lacking) to become established.

In cases where the primary policy support mechanism for solar is a solar RPS (e.g. New Jersey, Pennsylvania), regulators should monitor the relative percentage of utility owned solar versus customer owned solar. If the policy goal is to create a vibrant competitive market in a given state, policy makers should limit the total percentage of utility owned assets (excluding utility scale deployment) so as to meet this policy goal. Alternatively, RECs produced by a utility-owned solar facility should not be counted toward statutory REC compliance requirements.

Utilities should adopt and share a standard system interconnection procedure and provide net metering to all customers based on industry "best practices."

Regulatory Framework

The goal of the SA is to encourage the development of vibrant and diverse markets in each of these segments. State policy-makers should recognize that these market segments may require different approaches. In addition, the Solar Alliance supports the involvement of utility ownership and independent non-utility ownership models in all markets. Competitive markets that encourage a diversity of participants produce the best outcomes for ratepayers and participants alike. To this end, regulators should evaluate the ratepayer impact of a third party providing electricity under a long-term power purchase agreement (PPA) with the all-in per-kWh cost of energy of a utility-owned system on a comparable basis.

Finally, the SA supports the exploration of incentive mechanisms that can allow utilities to become agnostic to the issue of solar asset ownership. In traditional rate treatment, asset ownership is associated with regulated returns that compensate utilities for their investments (return of and return on capital) while support of customer ownership is not compensated beyond return of capital. Regulations should make utilities indifferent between owning a solar asset and entering into a power purchase agreement (PPA) or REC-only contract.