UTILITY-DRIVEN SOLAR ENERGY AS A LEAST-COST STRATEGY TO MEET RPS POLICY GOALS AND OPEN NEW MARKETS

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ABSTRACT

This paper demonstrates how utilities can develop and own distributed photovoltaic (DPV) resources to meet their renewable portfolio standard requirements. DPV resources produce valuable savings in generation, transmission and distribution peak demand, and create risk management and business benefits, all of which are internal to utility economics. These benefits can be maximized if the utility takes the lead in locating the DPV resource where, when and at the scale it is needed, and in designing and managing it to meet utility peak demands. A surprising conclusion from this analysis is that utility-driven DPV resources often save more than they cost, and can be less expensive than central station renewables. Utility-driven DPV may be the least-cost choice for utilities that have renewable energy generation requirements under their state's Renewable Portfolio Standard (RPS). As policy-makers and utilities understand this strategy, opportunities increase for reaching higher RPS goals more cost-effectively.

1. INTRODUCTION

Currently, 21 states and the District of Columbia have Renewable Portfolio Standards (RPS). Affected utilities must supply an increasing percentage of their retail energy needs each year with qualifying renewable energy resources and account for these resources with renewable energy credits (RECs). By 2020, RPS rules are expected to trigger development of more than 50 GW of renewable energy capacity nationwide, and this estimate is growing as more states set RPS goals every year. A 10 percent national RPS, which gained U.S. Senate approval in 2005, would push renewables development to 130 GW by 2020, according to Global Energy Advisors.

To date, solar energy has played a very small role in achieving RPS goals. Some states have included solar photovoltaic set-aside provisions (Arizona, Colorado, New Jersey, New York, Pennsylvania, and DC all aiming for less than 1%; Nevada seeking 5%), and a few indirectly promote solar. The purpose of RPS solar set-asides, from the legislators' perspective, is to diversify the utility portfolio, based on an understanding that wind is the dominant renewable, and that solar is the most expensive and least likely to be included without extra effort.

Some state RPS programs, for example New Jersey and Pennsylvania, provide for utilities to buy high-value RECs from customers that own PV systems, in effect creating a performance-based retail solar incentive. New Jersey solar RECs averaged $200/MWh from August 2004-2005, and are capped at $300/MWh. The solar REC market in Pennsylvania is untested, but REC values there reportedly may rise to the $600/MWh cap. All told, RPS policymakers who want to see solar at all on the resource radar screen expect utilities (and ratepayers) to pay well.

In this paper we describe a utility-driven, solar energy development business model in which utilities directly own distributed photovoltaic (DPV) systems on and adjacent to their customer's facilities. Locating DPV resources at the electric load produces significant peak-demand related savings in generation, transmission and distribution, as well as risk management and business benefits that are internal to utilities' economics. These benefits can be maximized if the utility takes the lead in locating the DPV resource where, when and at the scale it is needed, and in designing and managing it to meet utility peak demands.

A surprising conclusion from this analysis is that utility-driven DPV resources will be the least-cost resource to meet

RPS requirements for some utilities. If DPV resources can save more than they cost, then they are inherently less expensive than large-scale wind, biomass or other central station renewables. This is because the central station renewables do not have the beneficial effects on peak capacity investments throughout the utility system that well-managed distributed resources can produce. Utilities that implement this strategy can minimize the cost of RPS compliance, manage disruptive technology risk, reduce costs and rates and, if regulators approve, improve returns to utility shareholders.

The utility-driven DPV strategy will be useful first in states that have robust solar REC markets. We believe that as the solar industry matures utility DPV will be a least-cost RPS option for many utilities nationwide. As utilities gain experience accounting for the many benefits of distributed resources, DPV could well become a leading least-cost peak and intermediate capacity resource for non-RPS jurisdictions as well.

We conclude that if DPV is to play a strong role in solving the critical problems that drive RPS policies, from climate recovery to energy security, then industry leaders and policymakers must tap the readiness and reach of the utility market channel. If this utility-solar strategy is successful, it can stimulate growth of a new and potentially very large market for solar technology.

2. UTILITY-DRIVEN DISTRIBUTED PV BUSINESS MODEL

Utilities meet their RPS requirements by purchasing RECs from customers with solar energy systems or from third parties in the REC market. Direct utility investment in solar energy is an alternative to utilities buying RPS compliance RECs. This paper focuses on the benefits of utility investments in and ownership of *distributed* PV energy and capacity resources, as contrasted with centralized PV or concentrating solar power systems.

2.1 Overview

In our utility-driven DPV business model the utility's objective is to maximize the economic value of its solar energy investment, which then minimizes the cost of RPS compliance. DPV can reduce, defer or avoid costs in utility capital and operating budgets. Valuable savings are associated with peak-demand management that DPV can produce in generation, transmission and distribution systems. Further, DPV can be a potent risk management strategy, addressing a wide range of financial, technical, economic, regulatory, insurance, political, fiduciary, and market risks. It can build customer relationships and preserve the utility revenue stream.

To optimize cost-savings related to peak demand, the utility would locate the DPV resources as near to end-use electric loads as possible, for example, on or adjacent to buildings, municipal water pumping stations, substations, etc. If carefully planned and implemented, this would help to defer substation construction, reduce maintenance, line losses, and transmission congestion, provide voltage and VAR support and improve grid reliability, among others.

One key to a successful utility strategy is to design DPV for a high effective load carrying capacity (ELCC). This means that the solar resource would predictably have a high probability to serve the peak demand on the generation, transmission and/or distribution system. Design for ELCC criteria include:

- Location – where DPV can address grid problems
- Scale – match DPV resource to grid requirement
- Timing – build in time to effect change in traditional investment
- Orientation – match DPV resource output to grid or generation peak demand
- Maintenance – assure resource performance over time
- Integrate with dispatchable load management (direct load control, also known as demand response) and/or local energy storage

PV systems can have nearly 100% ELCC if they are combined with either local energy storage or load management capability.[1] A study of utility-scale solar load control opportunities for the Sacramento Municipal Utility District is one of several such studies that have found synergistic effects of integrating these technologies. "Operating PV (representing a 10 percent peak reduction) in tandem with an existing Direct Load Control (DLC) capability could "stretch" the dispatchable capacity of the DLC pool … by doubling the DLC instantaneous dispatchable capacity … (while imposing) considerably less cumulative impact on the customers (than DLC alone)." A 20 percent utility peak load reduction could be achieved with PV and just 12.4 hours of load control per year, compared to about 63 hours per year without PV. In this case, load control would virtually stretch the effective on-peak solar resource from 211 to 532 MW.[2]

2.2 Analysis of Utility Costs and Benefits

Utility analysts traditionally compare the busbar costs of various alternatives when they consider investments in new generation. That is, what is the cost per kWh at the output terminals of the generator? The comparison always results in PV being ranked as the most expensive generation alternative. Relatively low-cost coal plant busbar costs may be around 5 cents and PV may be 25 or 30 cents per kWh; most other generation alternatives, including wind, are clustered near the lower end of this range. The capital cost per kW may also be compared; natural gas-fired plants enjoy a 10 or 15 to 1 cost advantage over PV resources. Wind capital costs are 3 to 6 times cheaper than PV.

A completely different result is obtained by analyzing the *net resource cost* of DPV resources located on or near buildings where the power and grid support is needed. By locating at the load, DPV can change many aspects of the utility's economics from the load all the way back through the distribution, transmission and generation system. These beneficial effects of distributed resources may be worth enough in some (perhaps many) cases to tip investment decisions away from central-station fossil or remote wind to DPV resources.

To test the extent to which savings in traditional utility capital and operating costs can substantially change the economics of the DPV resource, we calculated the present value of utility-driven DPV benefits and costs from the perspective of a generic Northeastern utility, using estimates of a subset of terms drawn from Tables 1-3 below, including:

- Natural gas to run peak and intermediate power plants
- Peak generation capacity and O&M
- Distribution investment deferral
- Transmission congestion relief
- Environmental (Nitrogen Oxide controls)
- Line losses
- Avoided REC payments
- Retained customer revenue

The net present value of the utility benefit from owning DPV capacity was in excess of $6,000 per kW. We would expect similar results for many utilities throughout the U.S. Of course, each utility's system must be analyzed based on its technical details, policy environment, risk profile and economic circumstances.

Where DPV resources *save* more than they cost, they are *inherently* less expensive than wind, biomass or other remote or central station renewables. While a variety of renewable energy investments are advised in any utility energy resource portfolio, in this light, DPV has an edge.

The conclusion from this analysis is that utility owned DPV resources could be the least-cost resource to meet RPS requirements. And the analysis is conservative; we did not quantify values associated with risk management or the significant other terms listed in Tables 1-3. These additional values are potentially enormous.

2.3 Contrast with Customer-Driven PV

We compared the utility-driven DPV results with the traditional customer incentive-driven business model. In the customer-driven case the utility benefit was about $3500/kW, versus more than $6000 in the utility-driven model. The difference in value stemmed from three sources: customer owned systems have lower effective load carrying capacity, which reduces the location-specific peak capacity benefits; customers received REC payments from the utility; and the utility lost revenue due to the customer-owned PV system.

From a utility planner's perspective, customer-driven PV is an uncertain resource with regard to location, size, construction timing, peak resource timing, maintenance, and ELCC. At California PUC hearings in 2005, these issues prompted debate between utilities and solar advocates about the value of PV as a capacity resource. Consumer PV advocates, such as Vote Solar, assumed a 50 percent ELCC.[3] However, one utility asserted an ELCC value of just l4 percent, and other utilities raised similar concerns. Studies in New Jersey and elsewhere point to a 50 to 60 percent ELCC for customer-owned PV systems.[4] Even at that level of ELCC, a utility may convincingly assert that the solar resource would have very limited value.

From most customers' perspectives, utility investments in DPV would be welcomed as a way to help deploy more solar throughout the community. Utilities have patient money, low interest rates, technical skills, and a long-term outlook. They can put a PV system on a customer's roof or over its parking lot, include a host-site rate discount and liability coverage, and integrate it with storage and/or load controls. The customer visibly supports solar energy and has a lower electric bill, but has no investment risk, maintenance responsibility, property tax bill, etc. Moreover, this DPV resource is for the utility-as-a-whole, just like the rest of its system. All customers benefit equitably from the cost savings and risk reductions that the utility solar strategy brings to the table.

3. SOURCES OF DPV ECONOMIC VALUE[5]

A partial list of DPV economic value terms, short definitions (necessarily over-simplified due to limited space), and indicative economic values (if published) are listed in Tables 1 - 3. The "correct" value for most of these terms depends on internal utility data. Each utility has unique values for the costs and benefits of DPV at various locations and times on its system.[6] Not all of these terms may be relevant to each utility, and many are subject to changing market conditions. Table 1 summarizes the terms associated with traditional utility operating and capital budgets.

Table 1: Selected Sources of Value in Utility Budgets from Utility-Driven Distributed Photovoltaics

Source of Value	**Example or Value if Publicly Available**
Peak Load Value	
Distribution investment deferral[7]	< $0 to > $6000 per marginal kW for 5 year deferral
Transmission congestion relief[8]	$30 - $50/kW-yr
Transmission investment deferral[9]	$45/kW-yr
Generation capacity	$475/kW[10]; $1550 - $2000/kW if IGCC + Carbon sequestration[11]
Generation O&M[12]	~$10/kW-yr
Generation reserve capacity and O&M[13]	$.014/kWh for peak period
Natural gas[14]	$8.50/MMBTU; highly volatile future prices
Purchased power	PV supply curve offsets highest cost power in generation supply curve
Minimum load power plant dispatch[15]	$28/kW-yr
Environmental[16]	$0.014/kWh NO_X; also Mercury, SO_2, CO_2, PM10
Line losses	Up to 25% in some constrained systems
Reactive power[17]	$15/kW-yr
Voltage support	Varies; may be part of distribution investment deferral
Network O&M[18]	~ $16 to >$88/kW-yr
Intermediate Load Value	
Natural gas	$8.50/MMBTU; Peak + intermediate gas cost NPV $1800 - $3500/kW (increasing, with more volatility due to oil and gas depletion)
Environmental	$0.014/kWh NOx; others
Line losses	6% - 8%

Source: ElectricSUN synthesis from published studies of distributed energy resource benefits and costs, and oil and gas market data.

Table 2 identifies the public policy and business model-driven values. As an example, if a utility owns a DPV resource, it can be redeployed to defer successive distribution system investments.

Table 3 illustrates several risk management issues that are affected by the utility DPV strategy. These will be of special interest to institutional investors who are beginning to evaluate utilities' carbon risk, and to regulators concerned with price volatility and grid reliability.

Table 2: Policy and Business Model Economic Value from Utility-Driven Distributed Photovoltaics

Source of Value	**Example or Value if Publicly Available**
Policy-Driven Value	
Net metering payments	Normal utility rate; moving to Time-of-Use rate
Customer rebate payments	Varies by jurisdiction
Solar renewable energy credits	In NE US (PJM) region $200 - $600/MWh; others much less
Business Model Value	
Customer revenue retention	Normal revenue reduces non-participant cost issues
Peak-period DPV revenue	Sell DPV capacity into peak power market
Tax investor participation[19]	30% PV capital cost through '07; 10% after that
PV system portability[20]	~$2000/kW if redeployed 4x to dist. deferral projects
(Payment to PV host site)	Perhaps 10% of rate, plus insurance coverage

Source: ElectricSUN synthesis from published studies of distributed energy resource benefits and costs

Table 3: Risk Management Issues Affected by Utility-Driven Distributed Photovoltaics

Source of Value	**Example or Value if Publicly Available**
Grid reliability & outage prevention[21]	$Billions & lives lost -- societal
Natural gas availability	Threat of Fuel Use Act; oil and gas depletion; physical disruption from storm damage
Financial	Lower interest rates for PV due to lower risk
Regulatory	Avoid regulatory pre-emption
Carbon	New requirements likely
Insurance	Global warming liability coverage
Share price & fiduciary duty	Investor expectations for risk management leadership
Generation portfolio cost and risk	DPV net fixed cost reduces gen. portfolio cost & risk

Source: ElectricSUN synthesis from published studies of risk in the utility industry

4. DISCUSSION

Our perspective in this paper is to create a strategy to complement the existing and important customer-driven solar market. Customer incentives will continue to be crucial to the solar industry's growth. Implementing utility-driven solar, in addition to the customer-driven market, will bring much faster growth to the overall solar market.

Solar energy costs have declined by about 20 percent each time total industry capacity doubles. Recently installed, relatively large PV systems cost in the range of $4,500 to $9,000 or more per kW.[22] Typical prices for such projects have been in the range of $5500 - $6000. The low end of the range is from a recent set of projects totaling 5 MW implemented by the California Construction Authority. It benefited from use of thin-film PV and from economies of scale in purchasing and project management similar to those the utility model suggests.

At these typical PV prices the utility-driven DPV business model appears to be cost-effective now, without assuming heroic cost reductions or technology breakthroughs, though we believe these will happen. If our analysis is even approximately correct, there is a strong case that utilities can begin now to deploy DPV resources that save money, reduce risks, improve reliability, and reduce energy price volatility.

Utilities can plan their DPV programs to address the highest net resource value opportunities first. As solar prices decline, they can expand their programs to the lesser value locations, and increase their annual capacity purchases. Each annual increment of utility DPV capacity can be designed to save more than it costs.

We recognize that this strategy is a shift in corporate culture for utilities that some observers may regard as improbable. But these shifts are not entirely novel. Examples of this shift have begun to emerge as utility organizations adapt. One example is the Lakeland, FL municipal utility now develops, owns and profits from both PV and solar water heating systems on their customers' buildings. Before deregulation a number of utilities experimented with solar distributed generation, and quite a few have solar demonstration programs today. These programs can form the foundation of a solar resource program, and many parts of the utility – from account managers to distribution planning, risk management, fuel and power purchasing and others – will begin adding significant strategic value to the company by integrating DPV into the distribution system.

At the same time, regulatory policy support will likely be crucial to encourage utilities to develop their DPV resources. Solar set-asides as greater parts of state or federal RPS programs can invite utilities evaluate their solar REC purchases on a "make or buy" basis. The question is, will it be more profitable to deploy DPV, or to buy customer RECs? Just asking the question can reveal appropriate DPV applications.

Regulatory benefit sharing can further stimulate utility DPV development. This will need to address the various utility business structures that have been developed in the past decade, but the general principle is that where DPV saves more than it costs, it can provide savings to customers and returns to stockholders. Regulators could encourage such shared savings, so that utilities will have the incentive and motivation to carefully plan, implement and account for their DPV programs.

The scale of the potential utility-driven market is very large. A study for the Energy Foundation (EF) concluded the rooftop PV technical potential in the US is 1000 GW by 2025. However, they estimated that only 47 GW could be produced through the customer-driven model by 2025, and that is bullish next to the industry's PV Roadmap, also predicated on customer driven-demand. It forecasts less than 20 GW cumulative by 2020. While this is a lot of PV capacity, since only one GW is now installed in the US, these goals leave a tremendous market untapped, on rooftops as well on sites that were not counted in the EF study.

We have not estimated the market potential of the utility-driven model, though we believe this can and should be done. An initial market study might focus on RPS states and regions that have summer peak demands, where the utility-driven strategy will work best. We expect that the high value of these opportunities could drive a greater, national RPS, perhaps to a 20 percent national standard, with interstate tradable RECs. Such a policy could transform a potentially competitive relationship between the wind and solar industries into a highly collaborative one that also could encompass demand-response advocates.

Value chain management is a crucial issue. Utilities' procurement strategies will need to be structured to support and enable the rapid growth of the solar industry, so that it can supply the required capacity. This is non-trivial, and will require legislators, regulators and stakeholders to understand and support significant value chain management investments in capital, purchase contracts, and long-term commitments.

Further research is required to more fully develop this strategy. Market studies are needed. Utilities' organizational and regulatory constraints need to be resolved. Scale and timing of PV industry investment needs to be studied, and capital sources and structures to enable unprecedented growth must be designed.

5. <u>CONCLUSION</u>

Utility-driven DPV investments can be economically attractive, even at today's PV prices. No technical or research breakthroughs are required. What is required is new thinking in both organizational capability and business model innovation in both the utility industry and the solar industry. This paper demonstrates that solar energy can be cost-effective now, if implemented in a way that creates economic value for utilities, their customers and shareholders, and the solar industry.

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